THE PIPELINE INSPECTION, PROTECTION, ENFORCEMENT, AND SAFETY ACT OF 2006; IMPLEMENTATION REVIEW AND DISCUSSION OF SAFETY ASSESSMENT INTERVALS FOR NATURAL GAS PIPELINES

HEARING

BEFORE THE

SUBCOMMITTEE ON ENERGY AND AIR QUALITY

OF THE

COMMITTEE ON ENERGY AND COMMERCE

HOUSE OF REPRESENTATIVES

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CONTENTS

[1] Ms. Gerard did not submit a prepared statement.

THE PIPELINE INSPECTION, PROTECTION, ENFORCEMENT, AND SAFETY ACT OF 2006; IMPLEMENTATION REVIEW AND DISCUSSION OF SAFETY ASSESSMENT INTERVALS FOR NATURAL GAS PIPELINES

WEDNESDAY, MARCH 12, 2008

HOUSE OF REPRESENTATIVES,
SUBCOMMITTEE ON ENERGY AND AIR QUALITY,
COMMITTEE ON ENERGY AND COMMERCE,
Washington, DC.

The subcommittee met, pursuant to call, at 10:10 a.m., in room 2322 of the Rayburn House Office Building, Hon. Rick Boucher [chairman of the subcommittee] presiding.

Members present: Representatives Boucher, Butterfield, Barrow, Wynn, Inslee, Matheson, Dingell (ex officio), Upton, Walden, and Barton (ex officio).

Staff present: Bruce Harris, Laura Vaught, Chris Treanor, Rachel Bleshman, Alex Haurek, Tom Hassenboehler, David McCarthy, and Garrett Golding.

OPENING STATEMENT OF HON. G.K. BUTTERFIELD, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF NORTH CAROLINA

Mr. BUTTERFIELD [presiding]. At this time I am going to call the hearing to order. Thank you very much for your patience in waiting for us to start.

Today we have called this meeting to have a hearing on—and I am going to quote it verbatim, "The Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006; Implementation Review and Discussion of Safety Reassessment Intervals for Natural Gas Pipelines."

We have two witnesses on the first panel and I want to thank each one of them for coming forward today to be a part of this process. I want to thank the members for their participation today. I am going to begin with a very brief opening statement and then I will ask the ranking member if he would likewise give his opening statement and any member desiring not to make an opening statement will have that time added to your time later in the hearing. But I want to thank all of the witnesses today for coming to air their concerns about the issue of natural gas pipeline safety.

This committee can and will craft legislation to ensure proper compliance with safety regulations without becoming overly cumbersome for the industry responsible for abiding by this law. The committee shares jurisdiction with the Committee on Transportation and Infrastructure but it is this committee's goal to allow stakeholders an opportunity to express their concerns.

I would like to recognize and thank all of the witnesses at this time starting off with Mr. Carl Johnson, who is the Administrator for the Pipeline and Hazard Material Safety Administration for USDOT. Also joining him today is the Chief of Staff and I have her name, Stacey Gerard, who is the Chief Safety Officer who will be accompanying Mr. Johnson today.

The second panel will include Don Mason, who is the Commissioner for the Public Utilities Commission of the State of Ohio. Mr. Phillip D. Wright, who is the President of Williams Gas Pipeline Company and Rick Kessler, board member of Pipeline Safety Trust. Paul—I cannot pronounce that—Senior V.P. of Energy for Delivery Consumer's Energy and finally, Tim Felt, who is the President and CEO of Explorer Pipeline. Again, thank all of you for coming and thank you for your testimony today.

Mr. BUTTERFIELD. At this time I will recognize the gentleman from Michigan for his opening statement.

OPENING STATEMENT OF HON. FRED UPTON, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF MICHIGAN

Mr. UPTON. Thank you, Mr. Chairman. I also want to thank Chairman Boucher for calling this hearing to review the implementation of the PIPES Act of '06, a bill that passed under this committee on a bipartisan basis and was signed into law in December of 2006.

The U.S. currently has over 200,000 miles of oil pipelines and 260,000 miles of natural gas pipelines. Safety and security of this infrastructure is of the highest importance to our Nation and certainly worthy of this subcommittee's oversight. Pipelines are the arteries of our Nation's energy infrastructures. Through our thousands of miles of pipelines we transport the energy that fuels our economy in our daily lives. Unfortunately, recent accidents have thrust this vital infrastructure into the headlines for the wrong reasons and highlighted the need for safety reassessments.

The Pipeline and Hazardous Material Safety Administration, PHMSA, is in the process of working with the Pennsylvania PUC on a house explosion that occurred this last week. Tragically, two people were injured and taken to the hospital where one later died. One house was destroyed; another eight houses were damaged.

The National Transportation Safety Board is also closely following this terrible incident and they have new information linking the explosion to a gas pipeline leak. With proper safety assessments we can help assure that the terrible incident like this does not happen again. Given the vast size of our pipeline system and the limited resources at our disposal, it is imperative that safety inspections and regulations are as sufficient and productive as possible.

While today's hearing is rightly focused on the implementation and oversight issues of the PIPES Act, attention should also be given to allocating these finite resources in a more cost effective and efficient manner to assure that we absolutely maximize our safety efforts.

The issue of gas transmission lines, PHMSA was supportive of removing the 7 year requirement for a safety assessment in favor of a risk base interval during the debate of the PIPES Act and continues to be supportive of making a legislative fix today. We hear from industry and how an arbitrary, one size fits all, 7 year requirement could cause, in fact, more critical pipelines in high population areas to be assessed less frequently than necessary while resources are spent accessing other lines in remote areas that, in fact, could be more at risk. There is value in a risk base sorting approach, we can't inspect all the lines all the time but we can ensure that the public is indeed protected.

As noted by the GAO, it is widely recognized that a risk-based approach will help focus attention and resources where needed for the sake of increasing pipeline safety. I would agree that we should seek a legislative fix that would implement this risk-based assessment. Again, this issue has always been a strong bipartisan and important issue. I look forward to hearing from the agency, our witnesses today, and the challenges that they face in meeting some of these deadlines that are in this PIPES Act.

I would yield back the balance of my time, Mr. Chairman.

Mr. BUTTERFIELD. I want to thank you, gentleman. The gentleman from Washington, Mr. Inslee?

Mr. INSLEE. I will reserve my opening, thank you.

Mr. BUTTERFIELD. The gentleman reserves. The ranking members recognize Mr. Barton.

Mr. BARTON. Thank you. Thank you, Mr. Chairman. It is good to see you in the chair. It is going to be an enjoyable experience.

Mr. BUTTERFIELD. It reminds me of being a judge many years ago, though I will not lock up anyone up today, I promise you.

OPENING STATEMENT OF HON. JOE BARTON, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF TEXAS

Mr. BARTON. They have that authority. Mr. Chairman, the bill that we are reviewing today passed in the last few days of my chairmanship back in 2006, I was very active on this issue. We have a strong pipeline interstate pipeline system in Texas plus the intrastate, I mean, the intrastate system in Texas plus the interstate system nationally and had the problem of Alaska. It accelerated the need to reauthorize the pipeline bill.

I know there is some concern about it, especially the assessment period and things like this so it is very applicable to be holding this hearing. Having said that, I think we all know that our pipeline system in the United States is the envy of the world. It has performed admirably for decades and decades and as we get better technology and better metallurgy we always find ways that we can improve our inspections and improve our maintenance of the pipeline system.

I think it is also important that we review the past legislation because as we move into an alternative energy situation, there are growing calls for ethanol pipelines. And I think you are going to probably see as we build some L & G facilities off the east and west coast some demands to build additional pipelines to transport natural gas from the coasts to the internal areas of our country.

So we are glad to have our new administrator here, Mr. Johnson. He has got a tremendous record of public service and is that rare breed who has actually served on the Hill, where he knows what we do.

So as you know, Mr. Administrator, we have another hearing going on downstairs on food safety and the oversight subcommittee and we are expected to have several votes on the floor so you are going to see us coming and going this morning but we are delighted that you are here and you have your assistant and we look forward to hearing your testimony. With that Mr. Chairman, I yield back.

Mr. BUTTERFIELD. I want to thank the ranking member. I am being told that we have a very serious motion to adjourn on the floor right now and it is calling our attention elsewhere and so we are going to have to depart from the House floor and cast our vote and immediately return back to the room. But when we do return we are going to hear from these two witnesses :the Honorable Carl T. Johnson, who is the Administrator of the Pipeline and Hazardous Materials Safety Administration of the USDOT. We will also have the testimony of Ms. Stacey Gerard, who is the Chief Safety Officer for that organization. At this time the committee will stand in recess. Did I drop the ball on that? Did I have your title right? OK. All right. We are going to stand in recess and we will return just as quickly as we can. The committee is in recess.

[Recess.]

Mr. BOUCHER. The subcommittee will reconvene. I understand that in the previous hour we had opening statements by committee members and we have not heard from Mr. Johnson. And so Mr. Johnson, we want to welcome you to the subcommittee this morning and without objection to your prepared written statement will be made part of the record and we would welcome the oral summary of that statement for approximately 5 minutes. So we will be happy to hear from you at this time.

STATEMENT OF CARL T. JOHNSON, ADMINISTRATOR, PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION, U.S. DEPARTMENT OF TRANSPORTATION

Mr. JOHNSON. Thank you, Chairman Boucher, Ranking Member Upton. Thank you for the invitation to appear today. I am pleased to discuss the progress of the Pipeline and Hazardous Material Safety Administration in advancing safety. The enormity of PHMSA's mission, its complexity, and reach into the lives of every citizen makes it imperative that we succeed. I am committed to make this a great year for PHMSA and to help accomplish the most important safety priorities. We have improved our ability to investigate safety concerns. Not just incidents but the first indication of a problem.

We have been challenged this year responding to failures at several pipelines and I am sad to say that six people have lost their lives. The engineering issues have been difficult. We carefully examine operator safety performance, including the corporate commitment to safety. If it is lacking we build a better safety culture. Despite these incidents noted, the record in pipeline safety is good. Over the past 20 years, while population, energy consumption, and pipeline ton miles have been rising, the number of serious pipeline incidents has declined an average of 10 percent every 3 years. And this is no accident. It is a reflection of aggressive programs to reduce risk and protect the public.

As the Nation works to meet energy goals, several different opportunities confront us with unexpected urgency. The first is managing an expanded pipeline transport of products like ethanol. Our concerns are less if these new products can be moved safely but how they can be moved safely. A second challenge is increasing the reliability of the infrastructure we have. Thirdly, we face a pipeline building boom, bringing new designs, new materials, and new technologies. We have prepared and we must prepare communities and emergency responders.

We are working to address all of the many aspects of the PIPES Act provisions and its intent. Foremost is our emphasis on enforcement and we are more transparent about the vigor of our enforcement. On May 1, 2007, PHMSA rolled out its new enforcement transparency Web site and we are near completing all of the regulatory mandates of the PIPES Act. These include distribution integrity management and including excess flow valves, low-stress pipelines, and control room management including the risk of fatigue and the effectiveness of alarms.

I have reviewed all of these rules and found these regulatory actions are well developed. Getting ready for DIMP is a lot more than a rule. It takes a system and we have built one. We have consensus standards, guidance, training, IT for databases, and more resources for oversight.

Getting 50 states to implement a performance standard takes a lot of work. We know you are concerned about the availability of public information on pipeline operations to communities in which they operate. We have been working with pipeline operators to pilot test criteria for future grant awards. Our aim is to have communities identify information they need, to have operators make that information understandable, and hopefully to use that information to benefit the safety of the community. We funded public viewing of two events sponsored by the Bellingham Trust and we are preparing to fund two professional associations of county and city government to increase public participation in pipeline projects.

Section 13 of the PIPES Act requires PHMSA to issue rules for the use of safety orders as an additional option for addressing pipeline integrity threats and we are about to finalize an interim final rule.

Regarding the 7 year assessment rule PHMSA reported to Congress on this topic last year. We believe that a scientific basis is the best way to inform safety decisions and the allocation of safety resources. We are prepared to make these decisions on a segment by segment basis, one operator at a time.

PHMSA very much appreciates the opportunity to report on the status of our progress with the PIPES Act implementation and I am committed to full compliance. Thank you and I would be pleased to answer questions that you may have.

[The prepared statement of Mr. Johnson follows:]

STATEMENT OF CARL T. JOHNSON

I. INTRODUCTION

Chairman Dingell, Ranking Member Barton, members of the Committee, thank you for the opportunity to appear today. I am pleased to discuss the progress of the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) in advancing safety, since the passage of the Pipeline Inspection, Protection, Enforcement and Safety (PIPES) Act in December, 2006. I am Carl Johnson, the new PHMSA administrator. Accompanying me is Stacey Gerard, Chief Safety Officer and Assistant Administrator of PHMSA.

As quickly as the months have passed for PHMSA since enactment of this important program reauthorization, I realize the months remaining in my term are passing even more quickly, and I am committed to make this a great year for PHMSA. We will continue to accomplish the most important safety priorities and realize our agency potential to provide the most critical protections for the American people while our Nation's reliance on the safe transportation of energy and hazardous materials increases. I must take this opportunity to say that your commitment to completing the timely reauthorization of the national pipeline safety program enormously increases our chances of success.

II. BUILDING A GREAT ORGANIZATION

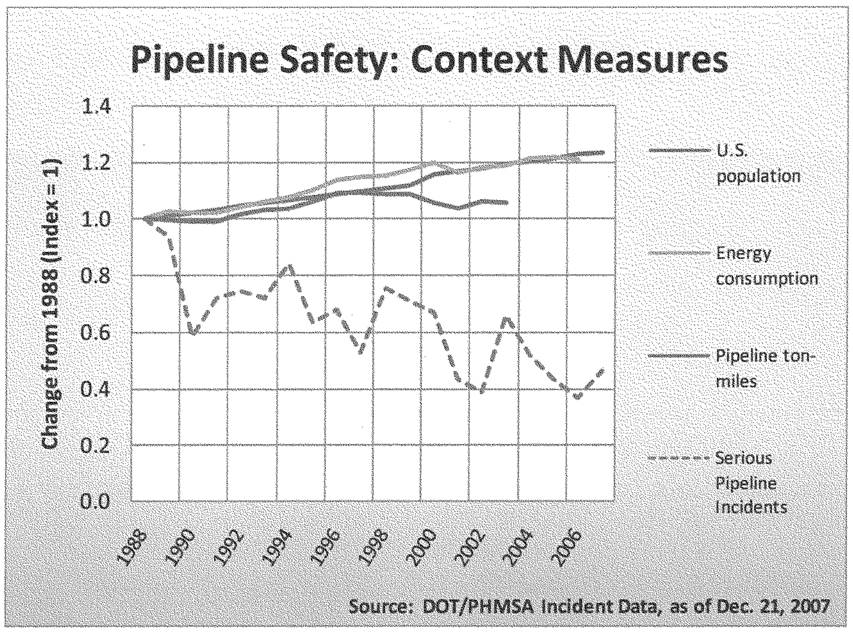
The enormity of PHMSA's mission—its complexity and reach into the lives of every citizen—makes it imperative that we are positioned to be successful. Just last month, the President forwarded to Congress the FY 2009 budget, the first budget PHMSA prepared since the passage of the PIPES Act. This budget frames our plan to get the resources needed to address the pipeline safety challenges the nation faces and that the PIPES Act recognizes. The resources requested will help us meet the intent of Congress to help provide states with more resources for oversight of the entire 1.9 million miles of infrastructure under their jurisdiction, help all pipeline safety stakeholders reduce damage to pipelines and help PHMSA build the capability to inspect and enforce to the full extent needed.

The recent completion of the ambitious PHMSA Strategic Plan, signed off by my predecessor and now Deputy Secretary of Transportation, Admiral Thomas Barrett, drives not only our budget request, but virtually all the actions of the agency. This Plan makes our job easier. It focuses on building our capability to make best use of information to drive down risk and guides the decisions we make—not only to improve the performance of PHMSA, but the entire hazardous materials transportation system. PHMSA strives to be a model agency—one that inspires confidence in our stakeholders because we have a risk-based rationale to guide our work that is transparent, meaningful, and easy to understand.

III. WE ARE ADVANCING SAFETY IN MANY WAYS

I believe we are doing just what we have promised in our Strategic Plan. Since the passage of the PIPES Act, we are making better use of information to improve safety. Perhaps most importantly, we have improved our ability to investigate safety issues—not just incidents, but the first indication of safety concerns. It is a priority for us to put more resources into investigations, preparing all our inspection and enforcement staff to understand the concept of root cause of pipeline failures and revamping our inspection and enforcement efforts to be even more effective.

Improvements of our investigative process have proven critical, for example, in guiding our oversight of all pipeline infrastructure in Alaska. We have been increasing our resources in Alaska and stepping up efforts to assist the state through the Petroleum Systems Integrity Office and the Joint Pipeline Office. This assistance includes directly delivering training from our Transportation Safety Institute, sharing data bases and information systems, and facilitating the inclusion of Alaska officials in meetings with other states through the National Association of State Pipeline Safety Representatives. Making better use of information guides all our actions. Most importantly, it guides our targeting of inspections and leads us to put special emphasis on operators whose performance need particular improvement. We work with companies to identify areas of concern and determine the appropriate level of effort needed for remediation. We have been particularly challenged this year working to respond to integrity issues for several pipelines of strategic importance to our national fuel supply which have experienced failures. Investigation is necessary to determine the extent to which the cause of failure is systemic and what is necessary to restore safe operations. Unfortunately, there have been incidents this past year, in Mississippi, Minnesota, Louisiana, Texas and California, sometimes caused by problems that are not easily remedied. I am sad to say that six people tragically lost their lives. More fortunately, our work with technology to advance operators' abilities to improve integrity, including the assessment of non-piggable pipelines, has achieved important results. Despite these incidents noted, the record in pipeline safety is good. Over the past 20 years, all the traditional measures of risk exposure have been rising—population, energy consumption, pipeline ton-miles. At the same time, the number of serious pipeline incidents—those involving death or injury—has declined by an average of ten percent every 2 years. This is "no accident." It's a reflection of aggressive programs to reduce risk and protect the public. We aim to continue this long-term trend.



We hope that the success of integrity management programs will continue to drive down the number of serious pipeline incidents and will help us make important inroads in greater safety in distribution systems. In fact, we believe this approach can benefit the entire hazardous materials transportation system.

We routinely examine operators' safety performance and identify what factors in companies' operations make the difference in improving their records. Further, we review the impact of different regulatory programs on safety in other industries. We inevitably come to the conclusion that individual corporate executives' commitment to safety and their effective management of information to drive down risk are critical. As a result, when we take action with an individual company with a poor performance record, we have begun to institute additional management requirements to help build a better "safety culture." At the same time, at the national level, in our work with trade associations, we are promoting focus on safety culture as a way to improve performance. At the national level, our efforts are intended to inspire improved performance—we are not considering regulating "safety culture." On an individual, remedial basis, however, we get more prescriptive. We detail how the company needs to create an environment in which risk information is brought forward and rewarded, how risk information is managed and tracked, and what is the adequate scientific basis for assessing and deciding how risk and control are measured. We are concerned about the transparency of this process and how safety and profitability values are balanced.

Helping communities deal with pipeline safety has been a priority of the past year as well. Of course, PHMSA always has at the top of our list of concerns using the best information available to guide our damage prevention efforts. Working with the Common Ground Alliance and all the underground damage prevention stakeholders, we target for assistance those states whose risk of construction related damage is the greatest or those states in which the potential for improvement is real. Among the program efforts of the past year is a stakeholder-driven collaboration on guidance, known as the Excavation Damage Prevention Initiative (EDPI) effort, to help states achieve full implementation of the "Nine Point Damage Prevention Program" codified in the PIPES Act. This guidance explains to state agencies what is intended in the "nine point program" and how to get there. We are putting representatives in the field to help explain the benefits of the program. We have also invested in a pilot research effort in Virginia to test ways of improving excavation location and communications technology so that the one call notification system is more accurate, works faster, and contributes to a safer work place. And of course, we have supported educating the public on the importance of calling 811, to help prevent damage to pipelines during an excavation. Pipeline operators believe that this number is effective in preventing damage to their facilities, and many are voluntarily adding this number to their permanent pipeline markers.

There are other ways to help communities live safely with pipelines. One of the most important of these is guiding communities to make safe land use decisions. Building on the model of the Common Ground Alliance, in the past year we have called stakeholders together in a similar model, called Pipeline and Informed Planning Alliance (PIPA). This is a follow-up activity to a mandate of the Pipeline Safety Improvement Act (PSIA) of 2002, and results from a recommendation by the Transportation Research Board.

A companion effort is helping communities understand where pipelines are located, who owns and operates them, and what other information is available for community planning. Following the passage of the PIPES Act, PHMSA worked with the Department of Homeland Security/ Transportation Safety Administration to resolve concerns about security sensitive information. Vital information that communities need for land use, environmental and emergency planning around pipelines is now publicly available through PHMSA's National Pipeline Mapping System (NPMS). We continue to work with states, industry and other stakeholders to make the NPMS information more accurate and more useful. Additionally, we have completed a review of thousands of operators' public education programs and provide operators with feedback.

IV. RELIABLE FUEL SUPPLY PRESENTS NEW CHALLENGES

As the Nation realizes the need to work toward the President's goal of reduced oil consumption over the next ten years, several different opportunities surface for PHMSA, and they confront us with unexpected urgency. The first is the challenge associated with managing a new set of products with properties we have not managed on a large scale in pipeline transportation—products like ethanol, hydrogen, carbon dioxide and potentially other biofuels. Some of these we are familiar with, but we expect the scale of operations to grow. Others, like ethanol, bring new technical issues we really have not confronted to the extent now contemplated. The second challenge is the need to increase the reliability of the infrastructure in place and, if possible, to get more capacity from it—more throughput. Thirdly, we face a pipeline building boom for the first time in decades, bringing the challenge of new designs, new materials, and new technologies to review and hopefully find acceptable. In FY 2007, PHMSA spent 14 percent of its field inspection time overseeing new construction, compared to 2 percent the prior year.

Another challenge is the need to work with the communities through which these products will be transported and help them understand the need for these products, the benefits they provide, the protections in place, and most importantly, how to respond to them in the event of an incident. Pipeline operators, in particular, have moved quickly to be ready to transport large volumes of ethanol, either in existing pipelines, retrofitted and dedicated to ethanol service, blended with other petroleum products or in batches, or in new pipelines designed for the purpose. Ethanol poses very unique emergency response challenges, and PHMSA is responsible for helping communities prepare.

While we always work to set standards for safe transportation, we also work to remove impediments and any unnecessary regulatory overlaps. Our concern is less "if" these new products can be moved safety, but "how" can they move safely, and how can we contribute to making it happen easier and sooner. There are many opportunities we see for harmonizing regulatory approaches to simplify the program logic for the industry—to examine what various regulatory structures try to achieve, where there are gaps, where there are overlaps and where there are occasions to simplify. Essentially, we would like to have "one plan" that works to meet similar objectives with one approach to assess risk, prioritize risk control and evaluate effectiveness. We have been testing this concept in Alaska as we work with state and federal agencies to plan for improved safety performance in the future. The model of the Joint Pipeline Office certainly has bearing on broader Alaska pipeline operations and applications for the Alaska Gas project, on which we have design review responsibility already. We think there are broader opportunities for simplification to a policy of "no gaps, no overlaps" in other areas of PHMSA responsibility. Another challenge for PHMSA is hiring and maintaining qualified pipeline engineering staff. It is taking us longer to fill vacancies, however, we are on track to fill our vacancies in 2008. There is a pipeline construction boom happening at the same time many individuals are retiring. Industry is competing for the same talent. To meet this challenge, PHMSA is implementing new ways of attracting talent, including remotely deploying employees at regional locations where they can telework and address issues directly in the field.

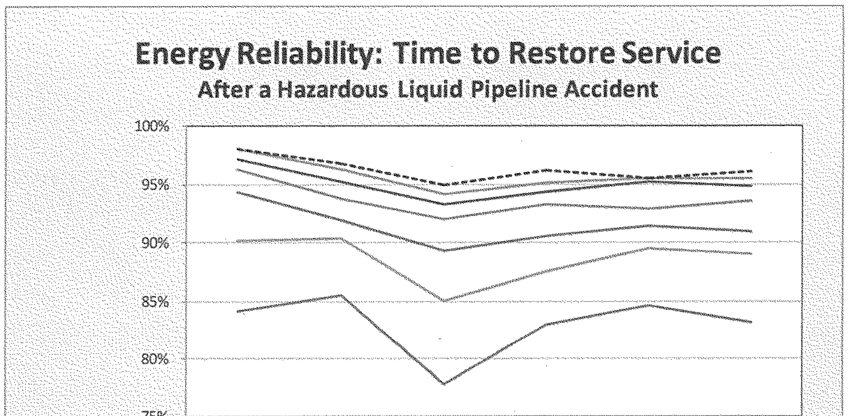
We have worked hard to step up to all these challenges. We notified the public of our intent to regulate these new products, if we weren't already regulating them. We continue to work with individual operators, identifying safety concerns that must be satisfied, both with the infrastructure and with the surrounding community. We work with other federal agencies to think about the transportation implications from the inception of marketing new fuels, as part of a systemic planning process. We work with other countries to benefit from their experience. We collaborate with the pipeline industry, the renewable fuels organizations, and others like emergency responder organizations and the National Commission on Energy Policy, to investigate and solve technical challenges.

Consistent with these efforts, PHMSA has investigated safety issues involved in allowing existing or proposed natural gas transmission pipelines to operate at higher pressure. Based on extensive examination by PHMSA, we have determined that improved technology in metallurgy and pipe manufacture, and improved pipeline life cycle management practices now give us the opportunity to ease supply constraints by allowing pipeline operating pressure to increase enough to boost capacity by as much as 10 percent. Increasing capacity also enhances pipeline efficiency. Higher operating pressures are consistent with practices in Canada, the United Kingdom and others.

We evaluated requests for special permits from companies seeking to operate existing or proposed pipelines at higher pressure. In granting the requested special permits, we required operators to demonstrate compliance with certain design specifications and imposed conditions requiring adherence to additional safety standards. In addition to allowing public comment on the requests for special permits, PHMSA held a public meeting and brought stakeholders into the development of the permitting criteria. As a result, PHMSA just proposed revising regulations to allow increased capacity. This will encourage the use of newer pipeline materials and associated safety standards, resulting in a net positive effect on overall pipeline safety.

While PHMSA has the ability to make regulatory changes benefiting natural gas transmission pipeline capacity, there is not an immediate pathway available to relieve constriction on oil pipelines. Consistent with the authorization in the PIPES Act, PHMSA is working with the Department of Energy and the Department of Homeland Security to develop an approach to investigation of "chokepoints" in the oil pipeline transportation system. We are scoping out an approach to modeling "what if" scenarios and the consequences of disruptions.

Any accident or incident poses a potential disruption to the delivery of energy supplies. While safety is always first, we are keenly aware of the need for reliable energy supply in the U.S. as well. We work closely with industry and our state partners to help safely restore service after a hazardous liquid pipeline accident, and 95 percent of the time this has been achieved within 7 days. With integrity management programs improving our understanding of pipeline condition and new technology available with more accurate diagnostic capabilities we can expedite the process to make sure these systems are safe to operate. In this way, we help make sure energy products are delivered not only safely but reliably.



	2002	2003	2004	2005	2006	2007
0 Days	68.0%	68.4%	62.0%	64.2%	66.2%	67.4%
Within 1 day	84.1%	85.5%	77.8%	83.0%	84.7%	83.2%
Within 2 days	90.2%	90.3%	85.0%	87.6%	89.5%	89.0%
Within 3 days	94.3%	91.9%	89.3%	90.6%	91.5%	91.0%
Within 4 days	96.3%	93.8%	92.0%	93.3%	92.9%	93.5%
Within 5 days	97.2%	95.2%	93.3%	94.3%	95.2%	94.8%
Within 6 days	98.0%	96.3%	94.1%	95.1%	95.5%	95.5%
Within 7 days	98.0%	96.8%	94.9%	96.2%	95.5%	96.1%

V. MEETING THE INTENT OF THE PIPES ACT

There are many aspects to the PIPES Act provisions and intents. Section 6 of the PIPES Act requires PHMSA to provide monthly updated summaries to the public of all enforcement actions and provide a mechanism for operators to make responsive information available to the public. This emphasis on enforcement programs, and particularly the need to make more transparent to the public the vigor and comprehensiveness of our enforcement efforts, is a high priority to PHMSA. In the year since the passage of the PIPES Act, PHMSA engaged in an intensive and productive pipeline enforcement period. We are very proud of these efforts and believe that they reflect a shared commitment by Congress, the Administration, and DOT to use the full range of civil and criminal enforcement tools under the Federal Pipeline Safety Laws to maintain a safe and reliable oil and gas pipeline transportation system.

On May 1, 2007, PHMSA rolled out its new enforcement transparency website, eight months ahead of the schedule set in the PIPES Act. This enforcement information can be found at *(http://primis.phmsa.dot.gov/comm/reports/enforce/Enforcement.html)*.While the PIPES Act requires us to post monthly summaries, we have chosen to do more. We do not merely post summaries of our enforcement actions. We provide access to copies of the actual enforcement documents filed by PHMSA and the operators' responses. We provide a brief narrative describing how each part of our enforcement process works, the penalties assessed, and the recent enforcement history of operators. All of this data is searchable by year, type of action, and other factors. The project is still in its infancy, and the history available and quality of the project will only improve with time.

We made this extra effort and went beyond the requirements of the Act. Transparency in the enforcement process provides notice to the industry as to what sort of regulatory violations we consider serious, what types of enforcement actions such violations are likely to evoke from PHMSA, and what the costs of non-compliance are likely to be. We believe this is already leading to improved performance. Transparency also alerts the public as to what we are doing as public servants, what the compliance performance of operators has been, what progress is being made, and where this agency needs to improve. We subscribe to the theory that transparency, when coupled with useful and reliable data, will lead to self-correcting behavior, both on the part of the regulated community and on the part of government itself.

We have been impressed but not surprised with the response we have received to this transparency initiative. We are currently seeing 800 "hits" per day on the website from non-DOT sources—from industry, local governments, and interested citizens. The website is also making us, as a government agency, more vigilant in making sure that our enforcement efforts are legally sound, that we are treating all operators fairly, and that the penalties we impose are commensurate with the impact of incidents and violations from which they arise.

As to the vigor of PHMSA enforcement, we initiated 259 pipeline enforcement actions in 2007, the second highest number since 2002. Seven of these involved corrective action orders (CAOs) issued in response to incidents causing fatalities or serious injury, hazardous liquid spills that damaged the environment, or other conditions posing serious threats to public safety or the environment. When serious incidents occurred, we responded immediately to the scene, ordered the operator to reduce the operating pressure of their lines or shut them down completely until remedial action could be taken.

The number of CAOs to which operators have satisfactorily responded, completing the compliance actions required by PHMSA, and allowing the agency to close the cases, has been increasing steadily since 2002. In that year, only two CAOs were completed and closed, as opposed to 14 in 2007. In each case, a hazardous facility has been made safe to operate.

PHMSA continues to make full use of its penalty authority. In 2007, PHMSA proposed civil penalties of $4,288,800, a 39 percent increase from 2006 and the second highest amount since 2002.

Continuing to take advantage of the full range of enforcement tools available to us, we opt for our best prosecutorial weapon. In July 2007, PHMSA and the Department of Justice announced the settlement of a civil action against El Paso Pipeline Company, arising out of a tragic incident near Carlsbad, New Mexico, in which 12 people were killed. This settlement was reflected in a judicial consent decree that included a civil penalty of $15.5 million and injunctive relief worth $86 million. This case represents the largest judicial settlement ever brought under the Federal Pipeline Safety Laws.

The most intensive enforcement effort PHMSA undertook since the passage of the PIPES Act has been our work in Alaska. The 2006 BP oil spills on Alaska's North Slope demonstrated the vulnerability of this environmentally sensitive area to major oil spills and the country's vulnerability to disruptions in critical supplies of crude oil from Alaska. It also focused extensive media attention on the need to strengthen environmental and safety oversight of the entire oil and gas industry in Alaska. As a result of these incidents, PHMSA has taken the lead in trying to forge a new regulatory and enforcement partnership, based on the concept of "One Plan," to meet the needs of various state and federal agencies.

As part of this work in Alaska, PHMSA has issued a CAO and three Amendments against BP to correct systemic problems in its pipeline system on the North Slope. As reflected in these orders, BP committed to the $260 million replacement of 16 miles of oil transit lines where the 2006 failures occurred. We signed a letter of intent with the State of Alaska Department of Natural Resources to improve state-federal cooperation in the oversight of the oil and gas pipeline industry throughout the state. We provided technical assistance to the U.S. Attorney for Alaska and the Environment and Natural Resources Division of the Department of Justice in their prosecution of a criminal case against BP, in which the company pled guilty to criminal negligence related to the maintenance of the Prudhoe Bay oil transit lines in November 2007. In that case, BP agreed to pay a penalty of $20 million for the 2006 spills.

PHMSA issued several enforcement actions against Alyeska Pipeline, the owner of the Trans-Alaska Pipeline System (TAPS) including a Notice of Probable Violation, with a proposed penalty of $817,000 for alleged safety violations relating to a pump station fire, inadequate cathodic protection, and other safety issues that threaten the integrity and reliability of this critical infrastructure.

As our regulatory focus has changed, so has our enforcement focus. It is becoming increasingly complex and innovative. Our work in Alaska is just one example where we "think outside the box" to devise enforcement solutions that better comport with the agency's rising safety goals. It means that we must forge new relationships among regulatory agencies and other stakeholders, such as the one we're building in Alaska, to design solutions that fit the circumstances. We are undertaking enforcement actions that seek to help instill a genuine "safety culture" within companies that have demonstrated a "tin ear" to placing safety first. We strive to be leaders in this effort. We do use our full range of enforcement options to encourage operators to do more than meet the letter of the law and to make our Nation's pipeline system even safer.

Beyond our focus in the past year on enforcement transparency and vigor, we have been working on all the statutory mandates of the PIPES Act.

A noteworthy provision helps states with more resources for oversight of the entire 1.9 million miles of infrastructure under their jurisdiction and helps all pipeline safety stakeholders reduce damage to pipelines. The President's FY 2009 budget does make important strides to increase funding to state agencies, and our request would increase funding on average about 50 percent over prior year funding and get us much closed to the goal of reimbursing states up to 80 percent of their program costs. PHMSA is also striving to comply with the standard in the Act pertaining to the necessary level of inspection and enforcement personnel. Similarly, in the area of damage prevention assistance, we ask for and are providing additional resources to help states achieve performance of all nine program elements. We are very actively involved in advancing damage prevention efforts.

PHMSA is also addressing all the additional requirements in the reauthorization. There are three significant regulatory mandates in the PIPES Act: 1) Distribution Integrity Management (DIMP), including excess flow valves (EFVs); 2) Low-Stress Pipelines; and 3) Control Room Management, including the risk of fatigue and confidence in and adequacy of alarms. For each of these initiatives, PHMSA's regulatory actions are well developed, supported with thorough regulatory analyses, and at advanced stages of review.

Section 9 of the PIPES Act requires PHMSA to prescribe minimum standards for integrity management programs for distribution programs, including requiring operators to install EFVs in certain circumstances. We are gathering additional data and completing analyses to complete the requirements for mandating the installation of EFVs. We asked our state partners to remind operators of the deadline in the law and they are doing so. We are moving the DIMP proposal to publication, but getting ready for DIMP is a lot more than a rule. It takes a system—and we built one. We have consensus standards, guidance, training, IT for data bases, and more resources for oversight. Getting 50 states to implement a performance standard takes a lot more preparation than preparing a single federal entity.

Section 4 of the PIPES Act requires PHMSA to issue regulations for low-stress hazardous liquid pipelines. This mandate required us to promulgate a supplementary notice beyond our original proposal. With that step completed, we are in the final stages of completing the first phase of a final rule to cover the low-stress lines that pose the highest consequence to the environment.

Section 12 of the PIPES Act mandated that PHMSA issue regulations requiring operators to develop, implement, and submit for DOT approval a human factors management plan to reduce risks associated with human factors, including a maximum limit on the hours of service for controllers.

Section 19 of the PIPES Act requires PHMSA to issue standards to implement National Transportation Safety Board recommendations concerning Supervisory Control and Data Acquisition (SCADA) operation, including: (1) use of graphics; (2) review and audit of alarms on monitoring equipment; and (3) pipeline controller training. We have completed necessary data gathering and analyses, and are rapidly moving that proposal to publication addressing both sections. PHMSA addresses Sections 12 and 19 through one rulemaking which will help controllers recognize and move quickly to act on abnormal events and mitigate their consequences.

In each of these projects over the past year, PHMSA found ways to strengthen our original concepts and added additional elements to the initiatives. Each of these projects has also benefited from public dialogue in the past year intended to enrich information available to us as we formulate the regulatory solutions.

Section 21 of the PIPES Act mandated PHMSA to evaluate leak detection technology and submit a report to Congress on the effectiveness of leak detection systems utilized by operators of hazardous liquid pipelines. PHMSA examined the issue, drafted a report and posted it for public comment at the end of last year. We are assessing the additional input and moving quickly to finalize the report. We have invested in several research projects intended to improve the sensitivity of leak detection technology, particularly for hazardous liquid operators. As we work on advancing this technology, we believe we have adequate oversight in place to evaluate the leak detection capability of individual operators and have exercised authority as needed to compel system upgrades where warranted. Our report is available on our website in draft while we complete the final editing to include public comments.

A long standing concern of the Committee is the issue of availability of public information on pipeline operations to the communities in which they operate. Section 5 of the PIPES Act requires PHMSA to award the first three community information technical assistance grants as demonstration grants, up to $25,000 each, for the purpose of demonstrating and evaluating the utility of the grants. We have been working with pipeline operators to develop concepts for this project which we could "pilot test". We see this initiative as a partnership between operators and communities. Our aim is to have communities identify information they need on operators' performance, to have operators make that information understandable, and hopefully to use that information to benefit the safety of the community. We asked operators to assist us with moving this project forward on a pilot basis, preparatory to grants. The results of these pilots will inform the criteria we would use more broadly. We funded public viewing of two events sponsored by the Bellingham Trust. We are preparing to fund two professional associations of county and city government officials to represent the public interest in pipeline projects. We are encouraging them to increase public participation in a range of initiatives to protect pipelines and communities from risks, including but not limited to informing land use decisions near existing and new pipelines.

Section 13 of the PIPES Act requires PHMSA to issue rules for the use of safety orders as an additional option for addressing pipeline integrity threats. We are finalizing an interim final rule, that will be published shortly, establishing the procedural regulations for issuing safety orders and how notice and consultations will be provided. Operators will be provided with notice and opportunity for informal proceedings to determine the measures necessary to mitigate the concern. Once this enforcement option is available to us, we will be in a better position to ensure operators are addressing longer term conditions before they become immediate hazards. In keeping with our policy of transparency in all of our enforcement actions, all safety orders will be accessible to the public on our website.

I am committed to full implementation of the PIPES Act and the agency looks forward to achieving full compliance as soon as possible.

VI. Risk Based Approach to Seven-Year Assessment Intervals

Section 25 of the PIPES Act required PHMSA to review and comment on the GAO report on the seven-year assessment interval and send Congress legislative recommendations necessary to implement the conclusions of that report. PHMSA has reviewed our experience with gas transmission operators' implementation of integrity management and the report of the General Accountability Office on this subject. We reported our findings to Congress on this topic last year and recommended that Congress amend the law to provide us the authority to promulgate risk-based standards for pipeline reassessment. As a risk-based, data driven organization, we continue to believe that a scientific basis is the best way to inform safety decisions and the allocation of safety resources. We have demonstrated that as an agency, we and our state agency partners have the ability, experience and training to review the adequacy of engineering justification that would be presented to us by operators seeking to vary the reassessment interval. We recently held a public meeting on the technical basis for making decisions on assessment intervals. The bottom line is that we believe these decisions should be made on a case-by-case basis, one operator at a time, and segment by segment, so that relevant operating characteristics can be considered along with individual operator performance.

VII. Conclusion

PHMSA very much appreciates the opportunity to report on the status of our progress with PIPES Act implementation and overall pipeline safety program. We share your commitment to improving safety, environmental protection and reliability of our Nation's pipeline system.

Thank you. I would be pleased to answer any questions you may have.

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Mr. BOUCHER. Well, thank you very much, Mr. Johnson. We appreciate your being with us here this morning.

I am concerned about the record of your agency in complying with a number of deadlines that were established in association with the 2006 act and I want to explore with you this morning what those deadlines were and get a sense from you about why they were missed. And our purpose here is not to be critical, our purpose is to understand what needs to happen in order to make sure that the will of Congress that was expressed on a bipartisan basis by this committee as we constructed the 2006 act is carried out. So please understand that that is our purpose.

Let me review the record and point to a couple of key deadlines that you have missed and then I will ask you why that happened and what you intend to do with regard to these issues.

In a hearing in July of 2006, before this subcommittee, I inquired of Admiral Barrett who at that time was the administrator of the pipeline program when the department would publish criteria that would give guidance to local governments in applying for the Technical Assistance Grants. And these Technical Assistance Grants are designed to enable the local governments to participate effectively in various proceedings relating to pipeline safety that your agency or potentially other government lenities might be involved in conducting.

I was told by Admiral Barrett in July of 2006, that the guidance—these guidelines to localities would be published within 3 to 6 months and I actually have a transcript of that hearing which reflects that we had quite a conversation during which he committed repeatedly to publishing those criteria within 3 to 6 months of July of 2006. Well, here it is now almost 2 years later and those criteria, that guidance has not been published so my first question to you is why not? Now, I realize you have only been on the job about 2 months and so I am a little bit disabled in that I cannot blame you for all of these problems but I need your statement of intention with regard to when the guidance will be published as to what your criteria for awarding these Technical Assistance Grants will be. So can you give me a date?

Mr. JOHNSON. We have the criteria available and I believe we are ready to present them to you today. In fact, we do have copies of it that I have given to you this morning and it is ready to be published.

Mr. BOUCHER. Well, that is good news. So you get a clear passing grade on the first question. Now, I have got two other areas in which I suffer the same disability but I cannot blame Mr. Johnson, but I can get a statement from him of when we are going to get the clarifications that we need and the publication of rules. So the secondary was this: the 2006 law set a deadline of December 31, 2007, for your agency to publish an Integrity Management Plan rule and this would be integrity management for the natural gas distribution lines, which comprise fully 85 percent of natural gas pipelines, and that deadline was also missed. So when can we expect the rule to be published for Integrity Management Plans?

Mr. JOHNSON. Well, the agency fully understands and I believe that this is the rule that probably is the most important rule for us because it has the greatest potential for safety since distribution pipelines run through communities. The proposed plan has been drafted and I believe we will have it ready to be published this spring.

Mr. BOUCHER. Can you be more precise about when this spring?

Mr. JOHNSON. I cannot be completely precise about that because there are things that are beyond my control that will dictate that but I can give you an idea that it will be done before the end of June.

Mr. BOUCHER. Before June ends?

Mr. JOHNSON. Yes.

Mr. BOUCHER. OK. I am going to say to you what I said to Admiral Barrett when he was here. We are going to start the clock and let us hope that you are a better clock observer than he was.

Mr. JOHNSON. Well, I certainly hope so, sir.

Mr. BOUCHER. And so we fully anticipate that by June we will have that rule published and if it has not happened you will be visiting with us again. All right.

The third area was this, in the 2006 act for the first time regulation was imposed on low-stress pipelines and that was in the wake of a major oil spill on the Alaskan North Slope from a low-stress line, about 200,000 gallons was spilled on that occasion and so Congress in the 2006 act, for the first time, imposed regulation on the low-stress lines. And your agency was directed to publish regulations for low-stress lines also by December 31, 2007 and that deadline was also missed. When can we expect that rule to be published?

Mr. JOHNSON. We have worked consistently to address all the issues needed to complete the regulation in low-stress pipelines and again, I believe, we will have the phase I issue of the final rule out this summer.

Mr. BOUCHER. Can you be more specific about when this summer?

Mr. JOHNSON. Again, I would say probably before September.

Mr. BOUCHER. OK. Why is it taking so long to do that?

Mr. JOHNSON. I do not have a ready excuse for you, sir, except to say that we are committed to safety at PHMSA. This is an organization that is just totally focused on safety and the deadlines are taken very seriously.

The last 15 months for PHMSA have been particularly challenging. We have had a number of incidents of unusual nature that we have had to investigate, we have a very complex system of oversight on enforcement issues, we have had the emerging alternate fuel issue, which is affecting the pipeline transportation that came on very quickly. We have had the continuing focus on the Alaska pipeline issues and then also the maturing of PHMSA as an agency, which has been quite a challenge as well.

Mr. BOUCHER. But you still think it is going to take until September to publish this rule?

Mr. JOHNSON. Yes sir, I believe it will.

Mr. BOUCHER. Yes, all right. Well, I will have to express some disappointment that it has taken that long and will continue to take that long. Nevertheless, we will await with interest the publication of that rule and expect it will happen within that timeframe.

The study to which, I think, you referred in your statement suggests that the requirement in the 2006 law that there be a reinspection of pipelines every 7 years be repealed and that reinspections occur where evidence suggests that a reinspection is appropriate. What are your comments with regard to whether or not there should be a statutory repeal of that 7 year reinspection requirement? And if you believe that it ought to be repealed, how would your agency propose to oversee pipeline safety with a view toward making sure that a repeal of that annual or that every 7 year reinspection does not jeopardize safety? What steps would you take?

Mr. JOHNSON. Well, PHMSA is a risk-based data-driven safety organization and we believe that basically a scientific basis is the best way to make those decisions. And I think that if we are granted that, it would be on a case-by-case basis, pipeline by pipeline.

Mr. BOUCHER. But how would you know that a reinspection of a particular pipeline is needed? What kind of evidence would come to your attention?

Mr. JOHNSON. If I may, I think I might have our safety officer respond.

Mr. BOUCHER. Ms. Gerard, welcome back. We are glad to have you here.

STATEMENT OF STACEY GERARD, CHIEF SAFETY OFFICER, PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION, U.S. DEPARTMENT OF TRANSPORTATION

Ms. GERARD. Appreciate being here, sir. Thank you. We would require a notification by the operator that they intended to exercise some different interval than 7 years and we would on a case-by-case basis look at the design of the pipeline, how it was built, what kind of materials, what age, the operating history, the performance of the operator, and the environment in which it operated. And the performance of the operator in integrity management up to that point would certainly be considered.

Mr. BOUCHER. We have got a vote on the floor. We are trying to figure out how to deal with you and deal with that too. Well, do you believe we should follow the recommendation of this study and repeal that reinspection requirement?

Mr. JOHNSON. Yes, I do.

Mr. BOUCHER. Ms. Gerard, do you agree with that?

Ms. GERARD. Yes, sir.

Mr. BOUCHER. Well, I was listening to your answer at least out of one ear and I did not hear you tell me what kind of evidence you would be looking for and what process you would have to make sure that that sort of evidence is reaching you that a reinspection might be called for with regard to a particular pipeline. Now, this is what we would want to know and have some confidence that you have got a process in place. With some assurance that when a pipeline is beginning to encounter problems or that a reinspection otherwise would be called for that, that fact would in some way through your process come to your attention, that is what we are looking for.

Ms. GERARD. We would require the operator—if we entered into a rulemaking, we would require that they notify us of their intent to use an interval other than the 7 years, particularly if it was a longer interval. Remember that we have a very rigorous inspection program of each and every operator and have full data on what their performance has been to date; we know a lot about them. So we would require them to notify us and we would immediately look at the design of the pipeline, the age, what kind of technology assessment was used.

We would look at the operating experience of the line, the environment around the line and, most importantly, we would be looking at the performance of the operator, how good a job have they been doing so far in assessing, controlling, and evaluating risks? How well do they use information? So that review would be done on an individual basis but the trigger would be a notification.

Mr. BOUCHER. OK. Here is what I am going to ask. I am undecided about what if anything we should do with this. I would like for you to submit to us in writing a detailed statement of the process that you would undertake and the criteria that you would use to assure that inspections of pipelines take place in a way that guarantees safety, and we are continuing to have safety problems. I think there were five or so incidents just recently where there were fatalities associated with pipeline accidents and this is an area that requires constant vigilance. And if we are going to get away from the rigid 7-year schedule I would like to know in detail what is going to take its place and what your intentions as an agency to make sure that we could repeal that requirement consistently to safety.

Ms. GERARD. I should mention we did have a public meeting on this in January, so we are prepared to provide the details that you have asked for very quickly.

Mr. BOUCHER. All right. I really do need to go to the floor and vote, and as much as I do not want to, I am going to recess the subcommittee and I appreciate your patience. Mr. Upton, I am sure, will have some questions when he returns. Thank you.

[Recess.]

Mr. BOUCHER. Well, with the apologies of the subcommittee we will reconvene. Thank you very much, Mr. Johnson, for your patience. The ranking member of the subcommittee, the gentleman from Michigan, Mr. Upton is recognized for his questions.

Mr. UPTON. Well, thank you again, Mr. Chairman. Mr. Johnson, welcome again, a couple of things that I am interested in. In your testimony, you talked about new technologies I would be interested in hearing a little bit about some of the new technologies that we are likely to see in coming years invested in the pipelines across the country.

Mr. JOHNSON. Yes, I think I would like to defer to my Chief Safety Officer for that, again, emphasizing the newness of my——

Mr. UPTON. I understand.

Mr. JOHNSON [continuing]. Position and Stacey, would you?

Ms. GERARD. Sir, in the past few years we have supported 47 projects just focused on being able to detect and manage corrosion, for example. I think one of our most important priorities is being able to improve the sensitivity of technology, to be able to detect weaknesses in a pipe wall, to be able to make that technology more sensitive, to be able to detect a crack, for example, at the earliest possible stage. There are many pipelines through which an instrument cannot pass at all. Developing technologies to be able to assess without running an instrument like a pig through would be examples.

Mr. UPTON. Mr. Johnson, you talked a little bit about developing the standards in your testimony and for all 50 states that performance standards would have to be established by all 50 states.

Where are we in terms of the progress of the states agreeing to a standard and do we have 35 states or 30 or you know where are we and how long do you think that it will take?

Ms. GERARD. Prior to entering into the rulemaking stage we had a process of a series of workshops that took place in which we had representation from many states. One of the representatives in that process was Commissioner Mason, who will testify later. And we would take the results of our work to the National Association of Regulatory Commissioners meetings and give them an update on the approach we were taking.

We got resolutions from NARUC which expressed their preferred approach being a performance approach with simple elements that they could adopt and administer at the state level. So I am hopeful that as a result of the process we use to develop the approach that we are taking in rulemaking—that we will have the support of the states who need to adopt this as a state requirement.

Mr. UPTON. Mr. Kessler from the Pipeline Safety Trust is coming to testify on the second panel. He talks in his testimony a little bit about establishing a Web-based system that would allow public access to basic inspection information regarding specific pipelines. What are your thoughts in that regard and what type of precautions might be there so you think about the worst case scenario of someone trying to damage some of our pipelines?

Ms. GERARD. We are all for transparency and have made some important strides in that area. This one is more challenging because the inspection process is not a black and white decision; yes, the company did it, or no, the company did not. Our inspectors consult with each other and our regional directors, with outside experts and so the process of making a decision about the company's performance takes time. And we would be concerned about posting something that an inspector felt might not have been a completed effort or their best thought. We have no problem with posting completed actions of the agency but we would be concerned about publishing something that might not be the finished product.

Mr. UPTON. One of the reasons that this committee took the action that it did, the legislation that was adopted on a bipartisan basis was the different stories of what was going on in Alaska. One of the ideas, of course, that many of us came to and I referenced in my opening testimony was as it related to risk-based this scenario rather than just an automatic every 7 years. What has happened with you all watching over the pipelines in Alaska?

Ms. GERARD. Well, we regulate many pipelines in Alaska and we have stepped up our oversight given the—some significant events that have been experienced by more than one operator. Regarding the operators that we have the greatest concern about, we have taken enforcement action. We have itemized our concern in corrective action orders. We have been very detailed and amended those orders when necessary. Where it concerns the Alaska Pipeline, which we govern jointly with the BLM and the State of Alaska, we have worked hard to improve the framework for how we govern jointly, to be more efficient. The bottom line is that we are bringing forward integrity management to the pipelines in Alaska. They are at various stages of progress and for the pipelines that we had not regulated prior to the accident that BP had, we are bringing integrity management forward under enforcement orders. We expect this performance-based approach, which is also risk-based, to result in much better performance in the future.

Mr. UPTON. Thank you. I know my time has expired so I yield back. Thank you, Mr. Chairman.

Mr. BOUCHER. Thank you very much, Mr. Upton. The chairman of the full committee the gentleman from Michigan, Mr. Dingell, has joined us and is recognized for his questions.

Mr. DINGELL. Mr. Chairman, I thank you for your courtesy and I commend you for this hearing. Mr. Johnson, welcome to the committee. I understand you are new in your position and I would note that in your written testimony it takes about 14 pages to get through the items that I am about to address here.

I would begin by reminding you that the Mineta Act, which reorganized your agency in 2004, requires your agency to consider safety as its highest priority and it says nothing about increasing throughput—citing infrastructure, or regulatory overlaps.

Now, I have a number of questions about how the agency has been functioning. I repeat, I understand that you are new in your job but I would observe that these are questions that you are going to have to address so I will read the question and then ask—read the facts and then ask the question and I would appreciate a yes or no answer.

One, Section 9 of the Pipeline Inspection Protection Enforcement and Safety Act or the PIPES Act required your agency to promulgate regulations for an Integrity Management Program for natural gas distribution pipelines by December 31, 2007. Has your agency met that deadline? Yes or no.

Mr. JOHNSON. No.

Mr. DINGELL. Mr. Johnson, Section 13 of the PIPES Act required your agency to promulgate regulations strengthening your authority to issue safety orders in order to avoid risk to public safety, property, human life, and the environment. These regulations were due December 31, 2007, has your agency met that deadline?

Mr. JOHNSON. No.

Mr. DINGELL. Mr. Johnson, on Section 4 of the PIPES Act you are required to publish regulations relative to low-stress hazardous liquid pipelines to the same standards and regulations as other hazardous liquid lines by December 31, 2007, this committee spent a considerable amount of time and effort with your agency on this provision, have you met that deadline?

Mr. JOHNSON. No.

Mr. DINGELL. Now I understand that you have published a proposed rule but that the rulemaking has not been completed, is that correct?

Mr. JOHNSON. Yes.

Mr. DINGELL. Now Section 21 and 22 required your agency to conduct two studies on leak detection technology and corrosion control regulations by December 31, 2007. Has either study been published?

Mr. JOHNSON. On the Web site, the technical findings have been posted.

Mr. DINGELL. I am sorry.

Mr. JOHNSON. On the Web site, the findings of the survey have been published.

Mr. DINGELL. It has?

Mr. JOHNSON. Yes.

Mr. DINGELL. Which one is that?

Mr. JOHNSON. Twenty-one.

Mr. DINGELL. Twenty-one. So the Section 21, has the 22 been published?

Mr. JOHNSON. No.

Mr. DINGELL. The Pipeline Safety Improvement Act of 2002 required your agency to establish competitive procedures for the award of pipeline safety information grants to communities; this is a provision that was very much pushed by our good friend and chairman, Mr. Boucher. Our support for this program was reaffirmed in the 2006 act. Now 6 years after this requirement was first put into law, has your agency established these procedures?

Mr. JOHNSON. It was made available for the record today.

Mr. DINGELL. Today?

Mr. JOHNSON. Yes, sir.

Mr. DINGELL. Now, let us go back through this list and see if we get some commitments for agency action. First of will you please tell the committee about whether and when you will meet your obligations for the following requirements: a. the integrity management rule for distribution pipelines, when will that be or will your responsibilities be carried out?

Mr. JOHNSON. It will be published this spring, sir.

Mr. DINGELL. Now, with regard to safety orders, when will that responsibility be accomplished?

Mr. JOHNSON. That will be published this week, sir.

Mr. DINGELL. Now, low-stress pipelines, when will you accomplish your responsibilities there please?

Mr. JOHNSON. That will be published this summer, sir.

Mr. DINGELL. Leak detection and corrosion control, a major problem, when will your responsibilities there be completed?

Mr. JOHNSON. In about a month, sir.

Mr. DINGELL. About a month. Now, criteria for information grants to communities, a very essential part of making a grant is knowing what they are going to do, when, how, why, and what standards they will have to meet. When will that information and the criteria be properly assembled?

Mr. JOHNSON. As I mentioned, that criteria is available for the record today, sir.

Mr. DINGELL. Thank you. Mr. Chairman, I thank you for your courtesy. Mr. Johnson, I wish you good luck. You are falling into a spot where your predecessors have not performed their labors properly. I wish you good luck and hope that you will have better success in serving the public than have your predecessors.

Mr. Chairman, I would also like to note just one thing more. And that is that a former staff member of this committee, a valuable friend of most of us on the committee, one of the people who did the extraordinarily fine work in completing the pipeline safety legislation over the years, which was rather hallmark of the success of this committee, is with us and he will be testifying: Mr. Rick

Kessler. Mr. Kessler, welcome to the committee. Mr. Chairman, I thank you for your courtesy.

Mr. BOUCHER. Thank you, Mr. Dingell. The gentleman from Oregon, Mr. Walden is recognized for 5 minutes.

Mr. WALDEN. Thank you very much, Mr. Chairman. And obviously these are issues we care deeply about, especially those of us from the northwest where there were some failures. I want to follow up a bit on what the chairman just was talking about in terms of the deadlines. In your opinion, how much of a failure to meet some of these deadlines is attributable to a lack of resources either staffing or budgetary? Do you have the people and the money to comply with this law?

Mr. JOHNSON. I believe we have the people and the time. I think it has been more of a function of the distractions, and I should not say distractions, but the events that have occurred over the past 15 months. I mentioned them earlier. They were the number of incidents that we have had to investigate——

Mr. WALDEN. Right.

Mr. JOHNSON. The complexity of oversight and enforcement rules that we are working with, the speed with which the alternate fuels has emerged and its importance, and for pipelines. The number of—the amount of time and the continuing effort we have had on the various Alaska pipelines incidents, and also the relative newness of the agency itself and the maturing of that with the replacement of senior officials.

Mr. WALDEN. I know you have had some additional and unusual challenges certainly in the last year. I was also a member of the Oversight and Investigations Subcommittee as well as this one and I know we did some hearings. I am trying to remember which subcommittee did them on Pipeline Safety in Alaska and the problems there and I realize some of those were state driven issues, not federal, but hopefully that is getting resolved. I apologize for not being here earlier. I was in a subcommittee downstairs, Food Safety. And could you just briefly tell me the status on the Alaska situation with BP's field lines?

Mr. JOHNSON. My safety officer—Chief Safety Officer—Stacey Gerard has been devoting a lot of time to that——

Mr. WALDEN. Right.

Mr. JOHNSON [continuing]. And I would like for her to address that if she may?

Ms. GERARD. Well, we maintain and place corrective action orders which BP is complying with. Should there be a failure to meet all the terms we would take further enforcement action. We have enforcement action underway at this time which we are not at liberty to discuss. We are working actively with other federal agencies in this matter as well as the State of Alaska. And I am happy to say that we are working on applying integrity management as a general philosophic approach to all of Alaska. And so whether it is lines which we currently regulate or lines which are under the jurisdiction of Alaska——

Mr. WALDEN. Right.

Ms. GERARD. We have been spending a lot of time assisting Alaska in understanding and learning how to apply those concepts and harmonizing so that we have one set, one plan that will work for Alaska.

Mr. WALDEN. And you feel like you are making progress on that plan?

Ms. GERARD. We do.

Mr. WALDEN. OK. Good. In terms of this risk-based analysis because it seems to me that the requirement is every 7 years you are supposed to—they are supposed to be in check, can you speak just a little bit more about that because it seems to me that it makes more sense to—there are some lines they do not need to check every 7 years and there are others you probably need to check every 7 days. How do you make those decisions and are you able to?

Ms. GERARD. We did provide a report in late November that did identify several pages of criteria that spoke to the construction and the design of the pipeline, the type of metal, the type of coatings, and the operating performance of the line, the environment that it is in, and the performance of the operator and being able to assess and control risk. All those are factors that we would use to decide what was appropriate. We review these operators now; we are familiar with their programs. Should we move to a risk-based approach through regulation, we would put out a proposal, go through the rulemaking process, and we would require operators to notify us in the event they chose a different interval.

Mr. WALDEN. OK.

Ms. GERARD. And we would have the opportunity to review how well that operator addressed the criteria and I also would point out we have a notification process in place like this today. Liquid operators, for example, if they are going to use an alternative form of testing notify us. We have the opportunity to inspect and make a decision and we post all those notifications on our Web site so it is quite transparent if an alternative is being considered and reviewed by the agency.

Mr. WALDEN. All right. Thank you. My time has expired. Mr. Chairman, I appreciate the witnesses and I look forward to the other panel.

Mr. BOUCHER. Thank you very much, Mr. Walden. The gentleman from Washington State, Mr. Inslee is recognized for a total of 8 minutes.

Mr. INSLEE. Thank you. This is has been something on my mind ever since the Bellingham tragedy and got to know the three families quite well and so I have been sort of committed to this issue for sometime. And it is with great frustration to think that all these number of years the Federal government is still not fulfilling its obligation to future families like this and it is just to tell you it is very disappointing after years of this effort knowing this tragedy in Bellingham that we are still not doing the job. I am just expressing that to you and I hope you share some of that frustration; you can pass it along to your organization, knowing how terrible a tragedy like this can be dealing with these volatile liquids. I want to ask you—you told us some new deadlines you have given yourself, having not met the statutorily imposed ones, what are the consequences for if there is going to be continued failure to meet what you have just told Mr. Dingell your new goal lines are?

Mr. JOHNSON. The consequences are very, very serious and I certainly take that commitment very seriously and I will assure you that I will meet those deadlines.

Mr. INSLEE. We hope that that is true and we hope that you through your agency find some way to discuss consequences if you do not meet them. I mean, frankly the statutory deadlines were pretty generous I thought at the time they were set given the length of period of time we have been working on this. So I hope you talk with your personnel about that, that there are some consequences and you internalize that in your agency to make sure this does not happen again. I want to ask you about the change of requirements of inspection, the 7 year requirement. Having seen up close and in person what can happen if you do not have a good management system, I am very reluctant to move away from mandatory requirement with a time period involved. And the reason is, is that a risk-based assessment, while intellectually satisfying and perhaps scientifically valid I have just seen it fail. We had discussions about the fact that BP had a risk-based assessment on their corrosion control and others I have seen this it just seems to have failed in real life because people—these managers have made assumptions about the corrosion in their pipelines and were just wrong. And they may not, through the lack of their intellectual ability or scrutiny or anything else, just that things were going on in their pipelines they did not know about and so it is I can understand the charm of it but to give my constituents certainty that these things are going to be checked, I am just very reluctant to move away from a statutory requirement. So what could you tell us about why I can have a higher level of guarantee to my clients with an uncertain risk-based approach that is subject to the discretion of all kinds of federal agencies, the same agencies that have not even met the statutory requirement that we set in the same industry that has had some of these repeated issues. How can that discretion give—and I know the parents of these three kids who were killed in Bellingham. If I go back and tell them we are now going to trust the discretion of this agency and discretion of corporate managers and they are going to come up with some formula, how could I possibly say that is as confidence creating as a firm deadline?

Mr. JOHNSON. I understand your concerns and I know you use the example of the BP corrosion; Stacey Gerard has had some very significant experience in that. I have not been there yet. I would like Stacey perhaps to address that.

Ms. GERARD. I want to say that we would not characterize the assessment process that BP had in place as an adequate risk-based process. I believe that if we had regulation in place that is in place in other segments of the industry, that accident would not have occurred. I think that we would not allow the decision to be at the discretion of the operator. We would have the checks and balances in place, where the operator would be required to notify us and we would conduct a review of the extent to which their plan met our criteria. We would not allow them to proceed if it did not. We have been growing and we have added resources to be able to spend more time in this kind of a review. I think the quality of the oversight is stronger and I think the overall record of reduction of serious incidents reflects that performance overall is improving.

Mr. INSLEE. You know I am looking at an article from the Seattle Times about the situation we're in. In the review of the Alaska pipelines a Seattle based engineering firm had concerns about their system, that essentially were whitewashed, I don't know if you are familiar with this or not. I will give it to you so you will be familiar with it but looking at what happened there, it just doesn't give me much confidence that there were will be some sort of rigorous scientific assessment that will be other than subject to the failures we have still recognized.

Ms. GERARD. Are you speaking about BP in particular?

Mr. INSLEE. Yes, yes and I have got nothing against BP, they have done some marvelous work in some other energy fields but I think it is indicative of why we just cannot have that high level of confidence when it is subject to some negotiation between the agency and the regulated industry. It may end up being 20 years, it may be 15, just to feel confidence that I can give people, and when you have 7 years it gives them some degree of confidence and I am just telling you, given the risk here and the tragedy that can unfold, I think we ought to, for a marginally less cost-effective regulatory system, trade that for a higher degree of confidence. That is what I believe. Given what has happened in the past in this industry and given the fact, frankly, this agency cannot even meet the standards that we have given you now, and now we are going to trust you to negotiate some risk-based assessment that you are going to apply to every single pipeline in the country. No, we cannot trust that. My constituents cannot trust that.

Ms. GERARD. We understand your disappointment. I do think that the products that we will produce shortly will be of a good quality and that any action that we would take should the Committee decide to let us do so, on the alternative approach on the intervals, will be publicly noticed. We get a lot of inquiries from the public about activities that are underway now and we feel it is our obligation to answer every one of them.

Mr. INSLEE. Yes, I understand, I am just—maybe I am not asking as many questions and making a statement here. I just think that I am not going to create confidence for a little bit of organizational simplicity here. That is just my belief. Thank you.

Mr. BOUCHER. Thank you, Mr. Inslee. The gentleman from Maryland, Mr. Wynn is recognized for 5 minutes.

Mr. WYNN. Thank you, Mr. Chairman.

Mr. BOUCHER. The gentleman is passing. The gentleman from Utah, Mr. Matheson is recognized for 5 minutes.

Mr. MATHESON. Thanks Mr. Chairman. I know we have talked a little bit about the Integrity Management Program; can you give me a sense of what percentage of overall natural gas transmission pipeline accidents are attributable to causes the Integrity Management Program is designed to address?

Mr. JOHNSON. I can probably provide that for the record. I do not have that in my mind at this point. I do not know—can you help him, Stacey?

Ms. GERARD. Well, the leading causes are being struck by a third party and corrosion, and we believe that that is the cause of the vast majority of the incidents, and that the Integrity Management Program is designed to detect corrosion. It is very strong in detecting corrosion and managing the prevention of damage through a variety of programs. That is all part of an Integrity Management Program.

Mr. MATHESON. Should we be concerned about the impact that not addressing the 7 year requirement that exists now, not looking to changing something else, could that have an affect on natural gas deliverability if we do not address that issue?

Ms. GERARD. We know that it is the position of the gas industry that it could affect deliverability. We are primarily concerned about safety, and we believe that the scientific approach is going to give us a better result and we are concerned about getting every community assessed. Base line assessment is a priority. We would rather get every community assessed first to make sure that every community has had the benefit of that safeguard.

Mr. MATHESON. Do you think with the Integrity Management Program set up the way it is today that directs funds to look for inspections, are we doing it in a way where we are focused on corrosion, you said in prevented accidents? Are we in that context missing or not directing resources to other potential threats to pipelines that affect the way the program is structured now?

Ms. GERARD. We have a very rigorous review of the operators' risk assessment. It is a 2-week review by a team of experts who we have spent millions of dollars training and keeping current with technology. They must look at every possible risk that pipeline faces, not just the leading causes. And a big issue is just because you have never faced that risk, are you doing everything you can to anticipate the risk that has not come along yet? That is one of the greatest challenges we face in working with operators on their risk assessments.

Mr. MATHESON. Let me then, I will ask my question a different way than that. Is the current way based on the legislation we have drafted, and the way it is being implemented, does it give you the flexibility to address risks in an appropriate way or would you like a more flexible way to deal with looking at potential risks in pipeline safety?

Ms. GERARD. It is our preference that you would give us the flexibility to use a rulemaking process to establish the criteria that would be used for the reassessment interval. We think it would encourage the best use of information that operators would be more vigilant in looking at risks and considering them. It is not that they are not vigilant today, but I think that the management process would be more dynamic and that it would encourage the allocation of resources to the greatest risk. That is what we think is most important. We are about driving down risk, and when we have limitations that are not science based, the potential for an allocation not to be to the greatest risk can happen.

Mr. MATHESON. OK. Thank you, Mr. Chairman. I will yield back my time.

Mr. BOUCHER. Well, thank you very much, Mr. Matheson. I want to say thank you, Mr. Johnson, for coming here this morning. I hope you have viewed this as a pleasant introduction to this subcommittee and let me echo the comments of Chairman Dingell: we wish you well in your work——

Mr. JOHNSON. Thank you.

Mr. BOUCHER. We are going to be interacting with you on a somewhat regular basis as the various timeframes—you announced in response to questions—are achieved, and we very much encourage you to meet those timeframes as you have said today that you will. You presented to us this morning for the first time a set of proposed criteria——

Mr. JOHNSON. Yes.

Mr. BOUCHER [continuing]. That you would apply for purposes of making grants for Technical Assistance Programs for communities. Now, while I realize that I have been asking for those criteria now for almost 2 years, and was promised those criteria about a year-and-a-half ago and now we have proposed criteria, I am going to ask that you delay the publication of those for a brief period. We would like to review them, to consider them, and perhaps to have a dialogue with you about them before you actually make those criteria public and that is a process that we hope to complete within approximately 1 month, but we will be back in touch. So do not call us we will call you and we will have a conversation about those criteria.

You have also indicated in response to questions that you would supply to us the steps that you would intend to take in the process to put in place that would substitute for the 7 year automatic reinspection schedule in the event that amendments are made to the law and that schedule no longer is applicable, and we look forward to receiving that. When, by the way, do you think you will be able to supply that to us?

Ms. GERARD. Two weeks to a month. We are going to draw on the criteria that we have submitted in the November letter and we are going to review the transcript of the January public meeting, so I would like to have a month.

Mr. BOUCHER. OK. A month is fine and we will look forward to receiving that document from you in approximately 1 month. Well, that is it, thank you for your attendance here this morning. Thank you for your cooperation and answering these questions and we certainly do wish you well in your work.

Mr. JOHNSON. Thank you very much.

Mr. BOUCHER. At this time let me introduce the second panel and we would ask them to come forward at this time. We have five witnesses on the second panel: Mr. Don Mason, who is a member of the Public Utilities Commission of the State of Ohio testifying this afternoon on behalf of the National Association of Regulatory Utility Commissioners; Mr. Phillip Wright, the President of Williams Gas Pipeline Company; Mr. Rick Kessler, who Chairman Dingell introduced some moments ago, who is a board member of the Pipeline Safety Trust and a former valuable staff member of this committee; Mr. Paul, I hope I am pronouncing this correctly, Preketes, Senior Vice President of Energy for Delivery for Consumers Energy; and Mr. Timothy Felt, President and Chief Executive Officer of Explorer Pipeline and Chairman of the Association of Oil Pipelines. And gentlemen, without objection your prepared written statements will be included in our record. We would welcome your oral summaries of those statements. And let me apologize to you in advance. I am going to have to depart before very long and Mr. Wynn from Maryland will be chairing the subcommittee in my absence and he will be taking the chair momentarily for that purpose and you will be in very good hands with Mr. Wynn. So welcome, we are delighted to have you with us. We will look forward to your oral statements. Please try to keep those to approximately 5 minutes. Mr. Mason, we will be happy to begin with you and you might move that microphone over.

STATEMENT OF DON MASON, COMMISSIONER, PUBLIC UTILITIES COMMISSION OF OHIO

Mr. MASON. Thank you, Mr. Chairman. It is always good to be before you and members of this committee. As a taxpayer, as a regulator, as a person that has been involved in pipeline safety we are actually pleased that the committee is involved in something of this technical nature it is again reassuring. I have been before you many times. I will summarize.

I think the important thing to realize is that states, utility commissions and those utilities that are regulated by the states are the ones who actually have to make the investments in terms of inspection time from the manpower side or investment money from the utility side. So we appreciate the regulations as Paul gave by PHMSA. We appreciate the legislation by Congress, but the bottom line is the boots on the ground are going to be somewhere on the state level. That is why in our prepared testimony we explain how many personnel there are out there representing the states about 325 doing the inspections. I think PHMSA has around 75—somewhere in that number—so again the burden is on the states.

In going back—and I am going off my prepared statements just to get to some very clear points—it takes money by the utilities to put into the infrastructure. Most of your utilities have filed rate cases with the state based on some sort of a hypothetical throughput of natural gas, some volumetric measurement.

With the increasing prices of natural gas, and you have all seen it, and your constituents have been very concerned by it, going from say $3 at MCF to $7, $8, $10, and even $12 at MCF in 2005. You saw reduced consumption by the consumers. Well, what that meant was that the gas companies who were making their money on that throughput received less money. Well, those rate cases were set up, included money for overhead, money for investment, money for safety, money for capital improvements. So when the volumetric throughput drops off, when customers quit burning gas because they need to save money, that is felt all the way through the system. What that basically means is at that point the utility does not have the money to invest.

So what I want you to know is that we appreciate the rules and regulations but this is a state issue as far as funding. Now, as Chairman of the NARU Committee on Gas, I have been pushing innovative rate design, called decoupling, and one of the purposes of decoupling is to incent the customer not to burn so much natural gas and incent the company to help create that message.

But the other thing it does, it affects what your concerns are today here. By having decouple methodology for rate design it allows the company to be neutral as far as revenue goes, when the customers start burning less and less gas.

So my point to the committee is, we appreciate the time and energy. We think PHMSA has been doing a very good job partnering with the states and I sort of wish Congressman Hall was here because I always like throwing him a few funnies when he is here but I would say getting state support is a lot like herding cats; it is really hard to do.

But the thing that PHMSA has really done with us is a re-step to NAPSER, which is the pipeline safety professionals, and they have reached out to NARU, which are the commissioners, is creating these partnerships. So when the rules are implemented, the rules will have that support, and this is important because states like Texas have completely different concerns about pipeline inspection than like in Ohio.

I know, for example, when the EFVs became a big issue about 2 years ago, we were quick to point out that in Ohio a great many gas distribution lines to the home are less than 10 pounds per square inch of pressure, so it would not even qualify for an EFV.

Likewise, the pipeline safety professionals in Texas brought to our attention, the problem with EFVs on some of their system is they are so close to the gas production and gathering that you would have constituents dropping out within the distribution system that could, in fact, gum up a valve and that is a non-technical term but it might cause the valve not to function properly.

So again, the point is, we appreciate the fact that PHMSA has used this broad-base approach working with pipeline safety professionals and working with the utility commissioners from all the states and regulated jurisdictions so then when you do have a product come before you it is something that will be functional and will work well. And again, my prepared statements are before you.

[The prepared statement of Mr. Mason follows:]

BEFORE THE
UNITED STATES HOUSE OF REPRESENTATIVES

COMMITTEE ON ENERGY AND COMMERCE,
SUBCOMMITTEE ON ENERGY AND AIR QUALITY

TESTIMONY OF THE HONORABLE DONALD L. MASON
COMMISSIONER, PUBLIC UTILITIES COMMISSION OF OHIO
ON BEHALF OF THE
NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

ON

"The Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006: Implementation Review and Discussion of Safety Reassessment Intervals for Natural Gas Pipelines"

March 12, 2008

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Summary of Remarks by
The Honorable Donald L. Mason
National Association of Regulatory Utility Commissioners
Before the
U.S. House of Representatives
Energy and Commerce Committee, Subcommittee on Energy and Air Quality

• Since 1968, States have been active partners in assisting the U.S. Department of Transportation Secretary in implementing the nation's pipeline safety programs. State pipeline personnel represent more than 80% of the State-federal inspection workforce and are the first line of defense in promoting pipeline safety, preventing underground utility damage, educating the public, and raising awareness regarding pipeline safety issues.

• After the passage of the PIPES Act of 2006, States have been working closely with the Pipelines and Hazardous Materials Safety Administration to fulfill the law's mandates.

• State pipeline safety program managers are essential to this relationship and are working with PHMSA on key elements of the pipeline safety program. These elements include excavation damage prevention, gas distribution, transmission and liquids management, public awareness communications, control room management, safety performance data collection and analysis, national consensus standards development, risk-based and integrated inspections, and planning for pipeline right-of-way encroachment.

• There are four key elements of pipeline safety: Minimizing excavation damage to pipelines; System integrity; Operator compliance with safety requirements; and Fiscal responsibility

• Programs mandated by the last three pipeline safety reauthorizations require extensive additional State efforts to address. Because oversight of these programs results in more inspection hours, State program managers are often short-staffed, and federal grant monies have not kept pace with the costs of providing the level of safety and compliance activities necessary.

• This issue was recognized in the PIPES Act, which authorized PHMSA to reimburse a State up to 80% of its personnel, equipment and activities costs required to carry out its responsibilities. PHMSA's current proposal to fund these programs at 60% should be supported, as it moves us closer to the congressionally mandated 80% number. Additional funding will lead directly to more inspectors on the ground and reduce the risk of pipeline accidents

Good morning Mr. Chairman, Ranking Member Upton, and Members of this Subcommittee. My name is Donald L. Mason. I am a member of the Public Utilities Commission of Ohio (PUCO). I am testifying today on behalf of the National Association of Regulatory Utility Commissioners (NARUC), where I am the immediate Past Chair of the Committee on Gas, and the National Association of Pipeline Safety Representatives (NAPSR). My testimony also reflects the views of the PUCO. Thank you for the opportunity to discuss our important role in supporting pipeline safety as it relates to The Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 ("PIPES Act"). This Act contains the necessary protections our nation depends on to safely maintain its energy pipeline network. The membership of NARUC and NAPSR appreciate this Subcommittee's interest in pipeline safety and I am pleased to provide testimony in support of the U.S. Department of Transportation (DOT) Secretary's efforts to fulfill the mandates of the PIPES Act and thus enhance the nation's pipeline safety.

NARUC is a quasi-governmental, non-profit organization founded in 1889. Our membership includes the State public utility commissions serving all States and territories. NARUC's mission is to serve the public interest by improving the quality and effectiveness of public utility regulation. Our members regulate the retail rates and services of electric, gas, water, and telephone utilities. We are obligated under the laws of our respective States to ensure the establishment and maintenance of such utility services as may be required by the public convenience and necessity and to ensure that such services are provided under rates and subject to terms and conditions of service that are just, reasonable, and non-discriminatory.

I ask that my testimony be made a part of the record and I will summarize our views.

Mr. Chairman, I will briefly describe to you the role of the States, where our efforts are currently focused, and what it takes in terms of State programs to support our partnership with the federal government.

Role of the States

Since 1968, when the Pipeline Safety Act was signed into law, the States have been active partners with the U.S. DOT Secretary in implementing the nation's pipeline safety program. In fact, State pipeline-safety personnel represent more than 80% of the State/federal inspection workforce. State inspectors are the "first line of defense" at the community level to promote pipeline safety, prevent underground utility damage, educate the public, and raise awareness of pipeline safety issues.

The resulting federal/State partnership is essential for ensuring the safe transportation of gas and hazardous liquids. At the State level, the responsibility for pipeline safety programs is carried out by approximately 325 qualified engineers and inspectors in the lower 48 states, District of Columbia and Puerto Rico. This number is approximately 3½ times the federal inspector workforce. Importantly, States have direct safety jurisdiction over 96% of regulated intrastate gas, and 32% of hazardous liquid systems and carbon dioxide facilities in the United States. Recent statistics indicate that States are responsible for pipeline safety covering more than 92%

of the 1.9 million miles of gas distribution piping in the nation, 16% of the 300,000 miles of gas transmission and 32% of the 166,000 miles of hazardous liquid pipelines.

Enhancing Pipeline Safety

Since passage of the PIPES Act, States have been working with the Pipelines and Hazardous Materials Safety Administration (PHMSA) in fulfilling the mandates of the Act. This is being accomplished in a two-pronged approach: (1) On mandates that are simple to carry out, processes are put in place that can yield immediate safety benefits (e.g., beefed-up enforcement); and (2) On multi-faceted mandates (e.g. excavation damage prevention), the States join federal-State task groups, and where appropriate, the industry as well, to concentrate on developing practical, effective and affordable solutions to implement the various aspects of such mandates. Although such efforts take more time, the result is a carefully crafted, sensible approach that is more likely to achieve the stated goal of the legislative mandate.

Essential to this partnership are the pipeline safety program managers in each of the 52 State agencies that are members of NAPSR. In addition to their intensive inspection oversight work schedules, many take extra time to address areas of concern dealing with existing challenges or new initiatives in pipeline safety. NAPSR currently has members on 19 task groups, with representatives from 30 States working with PHMSA on key safety elements of the pipeline safety program. These include, but are not limited to, excavation damage prevention, gas distribution, transmission and liquids integrity management, public awareness communications, control room management, safety performance data collection and analysis, national consensus standards development, risk-based and integrated inspections, and planning for pipeline right-of-way encroachment. With their knowledge and experience about conditions in their States, the NAPSR members provide unique expertise to the task groups.

Four Key Elements

One of the four key elements in pipeline safety is minimizing excavation damage to pipelines. NAPSR members have been working with PHMSA in developing the necessary implementation steps for the nine elements specified in the PIPES Act, while also carrying out projects each year which help promote One-Call programs and taking steps to put into practice other components of the nine-element program.

Another key element of pipeline safety is system integrity. Through NAPSR, States worked with recently a stakeholder group to develop the foundation of the soon-to-be-released Distribution integrity Management Program rule. They are now working with PHMSA to plan the implementation steps of this rule which will add integrity management coverage of almost two million miles of distribution pipelines under State jurisdiction. In anticipation of the rule, many NAPSR members are already overseeing installation of excess flow valves on residential service lines in their States. Also, State inspectors are overseeing existing pipeline integrity management programs under way in their respective States. It must be remembered that many States have long had integrity management programs in the form of additional and accelerated operating and maintenance activities, as well as planned replacement programs. These programs have been very effective in addressing the local needs of the individual distribution systems throughout the country, and are based on the actual circumstances affecting the individual systems. However, the new requirements are likely to increase the workload significantly, particularly in the area of written procedures and ongoing data collection and analysis.

The third key element to pipeline safety is continuing inspection efforts for operator compliance with the long-standing safety requirements that cover design, installation, initial testing, corrosion control and many operating and maintenance functions. While new sets of regulations have been developed to address recently identified needs, the enforcement of the original code requirements is essential to maintaining the basic levels of safety in our pipeline systems. Properly installed new facilities should minimize future integrity issues.

Finally, a fourth and critical key element in dealing with pipeline safety in practice is fiscal responsibility. Being responsible and directly accountable to our States' residents, we are sensitive to program costs to our ratepayers. As such, we consider practical ways of enhancing safety, which may include risk-based approaches to pipeline safety to allow the operators under our jurisdiction to focus their resources to where they are most needed, while enhancing or maintaining safety.

Through forums at NARUC and efforts of NAPSR, we work with our federal partner, PHMSA, to identify such areas. This also requires ensuring that proper data are collected by our operators and compiled by our program offices so that risks can be properly identified and assessed. Here again, our NAPSR members are engaged in an ongoing effort with PHMSA to collect reliable, high quality, relevant data on the characteristics and safety performance of the nation's gas and liquid fuel delivery systems. Part of fiscal responsibility is the federal government living up to its original promise from the Pipeline Safety Act of 1968 of 50% funding of State expenditures for pipeline safety (currently the level is approximately 40%) and expanding it toward the recently authorized 80% maximum funding allowance contained in the PIPES Act of 2006.

Transmission Pipeline Integrity Reassessment Interval

Transmission pipeline operators have stated that with the fixed seven-year integrity reassessment interval, their resources and the associated services will not necessarily be focused where they are most needed and will undergo a peak demand during the period from year eight through year 10. This occurs because of the overlap between the 10-year baseline assessment period and the 7-year reassessment period. Since there will be a peak workload in assessments during the overlap period, there will also likely be a peak integrity inspection workload for the States during that period. However, unlike industry, States do not have the resources to hire additional help if needed. This means that in some States where such workload is high, the ability to carry out the necessary pipeline safety compliance inspections within the required time intervals will be hampered during the three years of overlapping assessments. Flexibility in the reassessment interval, subject to the necessary safeguards, would help mitigate this problem.

Concluding Remarks

In summary, programs mandated by the last three pipeline safety reauthorizations require extensive additional State efforts to address safety in areas that include operator qualification requirements, gas transmission and liquids pipeline integrity, public awareness communications, excess flow valve installation, pipeline control room management distribution integrity, and excavation damage prevention. Because State oversight of these programs translates into more inspection-hours, State Program Managers are finding it increasingly difficult to carry out all of their responsibilities with current inspector staffing levels. As our staffs have had to grow so we can administer and enforce the new requirements, federal grant monies have not kept pace with the costs of providing the level of safety and compliance activities necessary. The States have had to assume a larger and larger share of the costs of providing for pipeline safety.

This was recognized in the PIPES Act, which authorized PHMSA to reimburse a State up to 80% of the cost of the personnel, equipment, and activities reasonably required to carry out pipeline safety activities in that State. For FY 2008, PHMSA has funds for reimbursing only 40% of State expenditures. The current PHMSA proposal to fund State programs at 60% is appropriate and should be supported. Now Congress must provide adequate funding for State pipeline safety grants and move toward the 80% federal funding level—as authorized under the PIPES Act—for State costs associated with the congressionally mandated expansion of pipeline safety programs. Additional funding for State programs will put more inspectors on the ground, resulting in more frequent inspections of pipeline operators and a reduced risk of pipeline accidents.

Like you, we understand the importance of our mission to the safety of our citizens, energy reliability and continued economic growth of our Nation.

Thank you for your attention. For your review and information, I have attached two policy resolutions approved by NARUC in February addressing some of the issues discussed here today and respectfully request that they be included in the record. I would be pleased to answer any questions you may have.

ATTACHMENTS

N A R U C

National Association of Regulatory Utility Commissioners

R E S O L U T I O N

Resolution on Congressional Appropriations for Pipeline Safety

WHEREAS, Since the Pipeline Safety Act was signed into law in 1968, States have been very active in assisting the U.S. Department of Transportation (DOT) Secretary to carry out the nation's pipeline safety program, State pipeline safety personnel represent more than 80 % of the State/federal inspection workforce and State inspectors are the "first line of defense" at the community level to promote pipeline safety, underground utility damage prevention, and public education and awareness regarding pipelines; *and*

WHEREAS, States have direct safety jurisdiction over 96% of regulated intrastate gas and 32% hazardous liquid systems and carbon dioxide facilities in the United States, and States are responsible for pipeline safety covering over 92% of 1.9 million miles of gas distribution piping in the nation, 15% of 320,000 miles of gas transmission and 33% of 160,000 miles of hazardous liquid pipelines; *and*

WHEREAS, Adequate funding is necessary to enable the States to conduct the required inspections of the existing pipeline facilities, new pipeline construction projects, and to encourage compliance with current and pending pipeline safety regulations; *and*

WHEREAS, Added programs mandated by the Accountable Pipeline Safety and Partnership Act of 1996 and the two pipeline safety reauthorizations that followed include, but are not limited to, operator qualification requirements, gas transmission and liquids pipeline integrity, public awareness communications, excess flow valve installation, pipeline control room management and distribution integrity management; *and*

WHEREAS, As a result of the shortfall in past Congressional appropriations, the federal matching grants to States have not been commensurate with the growth in pipeline safety program expenditures covered by State funds to carry out the above mandates; *and*

WHEREAS, The Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (PIPES Act) authorized PHMSA to reimburse a State up to 80 % of the cost of the personnel, equipment, and activities reasonably required to carry out pipeline safety activities in that State; *now, therefore, be it*

RESOLVED, That the Board of Directors of the National Association of Regulatory Utility Commissioners, convened in its 2008 Winter Meetings in Washington, D.C., urges Congressional appropriations bodies to adjust the Fiscal Year 2009 appropriations to DOT for State pipeline safety grants so that States are given the opportunity to recover at least 80% of the costs of the congressionally mandated expanded gas safety programs.

Sponsored by the Committee on Gas
Adopted by the Board of Directors February 20, 2008

N A R U C

National Association of Regulatory Utility Commissioners

R E S O L U T I O N

Resolution on Excavation Damage Prevention

WHEREAS, The Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (PIPES Act), which was signed into law in December 2006, established a new pipeline safety program focused on improving existing State "excavation damage prevention" programs; *and*

WHEREAS, Excavation damage is the number one cause of serious accidents to pipelines and other underground utilities; *and*

WHEREAS, This new pipeline safety program encourages States to enhance their damage prevention programs by incorporating nine "Elements" into their pipeline safety regulations and/or laws; *and*

WHEREAS, A group of excavation damage prevention stakeholders (composed of excavators, underground facility owners, operators, safety advocates, State regulators, and the public) participated in a three-year collaborative effort, drawing on their expertise and experiences in underground facility safety, operations, and excavation, to craft the nine "Elements"; *and*

WHEREAS, A stakeholder group formed the Excavation Damage Prevention Initiative (EDPI) in the summer of 2007 and produced a document titled "Guide to the Nine Elements" to provide guidance to stakeholders, State legislatures, and State commissions, working to incorporate the nine "Elements" into their States' existing State damage prevention programs; *and*

WHEREAS, State legislatures and State commissions are being asked to use the EDPI's "Guide to the Nine Elements" as a baseline for improving their current programs; *and*

WHEREAS, The PIPES Act requires that the Department of Transportation make grants available to States that undertake to incorporate the nine "Elements" into their damage prevention programs; *and*

WHEREAS, The Elements themselves contain processes and goals that when incorporated into State damage prevention programs, will enhance their effectiveness; *now, therefore, be it*

RESOLVED, That the Board of Directors of the National Association of Regulatory Utility Commissioners, convened in its 2008 Winter Meetings in Washington, D.C., urges State commissions to review their current excavation damage prevention programs and to consider the EDPI's "Guide to the Nine Elements" document in making revisions and improvements, where necessary, in order to incorporate fully the nine "Elements" of the PIPES Act of 2006.

Sponsored by the Committee on Gas
Adopted by the Board of Directors February 20, 2008

Mr. WRIGHT. Would you like to pause for questions or shall I go?

Mr. WYNN [presiding]. No, we would like each of the witnesses to go ahead and proceed and then at the conclusion we will take questions. Thank you.

STATEMENT OF PHILLIP D. WRIGHT, PRESIDENT, WILLIAMS GAS PIPELINE COMPANY

Mr. WRIGHT. Thank you, Mr. Chairman. My name is Phil Wright and I am President of Williams Gas Pipeline Company. Williams is the Nation's second largest transporter of natural gas. I also serve as Chairman of the Board of the Interstate Natural Gas Association. OK, thank you very much, sir. Again, my name is Phil Wright. I am President of Williams Gas Pipeline Company. Williams is the second largest transporter of natural gas in the Nation. I am also a Chairman of the Board of the Interstate Natural Gas Association of America, INGAA, on whose behalf I am testifying today. INGAA represents virtually all of the interstate natural gas pipelines in the United States and Canada. The mileage of the pipelines represented by INGAA totals over 200,000 miles.

I will begin with a quick report on integrity management and the integrity management program. The Act of 2002 included the requirement for PHMSA to develop a rulemaking on integrity management for natural gas transmission lines. The act required all operators to first identify all segments of pipeline located in populated or high consequence areas, undertake baseline assessments or inspections, if you will, of all these segments within 10 years and perform reassessments of those segments every 7 years thereafter.

The act also required that we complete at least 50 percent of our baseline assessments within 5 years of enactment. The 5-year way point in the baseline was reached this past December and I am pleased to report that the industry is on track for meeting the baseline requirement. In fact, as of December we have inspected over 51 percent of the high consequence pipeline mileage covered under the act. The number of actual anomalies that have been found to date requiring repair is small. This is a strong indicator that the maintenance practices operators use to protect the useful life of this vital infrastructure is effective. The inspection program is proactive. It helps us identify potential problems, mainly corrosion, and fix them before they become real problems.

So the Natural Gas Integrity Management Program is on schedule and working the way that Congress intended. This leads me to the focus of this hearing: the 7 year reassessment interval.

INGAA has consistently proposed that reassessment intervals should be set on a segment-by-segment basis, looking at the various risk factors and science to determine what the appropriate interval should be. The current 7 year requirement results in most attention and resources being concentrated almost entirely on corrosion problems, which are also one of the least likely causes of serious accidents. As well, the 7 year requirement in essence presumes that reassessments can be done with little or no impact on pipeline operations or natural gas deliverability. That presumption is without basis and fact. The impact is often significant and adds costs to consumers.

Mr. Chairman, numerous technical analyses of this issue have all suggested risk-based assessment intervals rather than an arbitrary fixed number. This conclusion has come from qualified stakeholders outside the pipeline industry. In quoting the general accounting office, we believe the title of their report in 2006 speaks for itself: "Risk-based Standards Should Allow Operators To Better Tailor Reassessments to Pipeline Threats." We believe the GAO's assessment is rightly concluded. We also want to make sure that there is clear understanding that corrosion is not the only safety factor facing pipelines. In fact, accidents due to corrosion, again, the focus of the reinspection interval, account for less than four percent of incidents resulting in death or injury. Clearly the industry sees a need to mitigate the effects of corrosion and we are meeting that need, as evidenced by the data. In prioritizing our resources, we think you would agree that our efforts are best focused on those causes that give rise to the greatest number of incidents such as external damage prevention.

You have before you official recommendations from both GAO and DOT, and my written testimony covers much more on the issue. INGAA urges Congress to adopt the statutory language proposed by DOT Deputy Secretary Barrett in November of last year. We believe—in fact, the GAO and DOT believe—doing so would improve the safety of pipelines by better focusing our efforts.

Unintentional damage to our pipelines from excavation is the leading cause of deaths and injuries associated with natural gas transmission. Going forward we really believe that should be the area of concentration of our improvement efforts.

At the request of the leadership of PHMSA staff, my company volunteered to undertake a pilot community assessment program focused on educating local policy makers on pipelines and pipeline safety, deploying state of the art technology and working to develop programs that prevent pipeline accidents. Williams is working with Fairfax County, Virginia, which has an excellent One Call program on this pilot and we believe it will help prevent damage, excavation damage, in that rapidly growing community. We hope this effort can be extended to other communities across the country. Thank you, Mr. Chairman and members of the subcommittee, and I will be happy to respond to questions.

[The prepared statement of Mr. Wright follows:]

TESTIMONY OF
PHILLIP D. WRIGHT
PRESIDENT
WILLIAMS GAS PIPELINE COMPANY

ON BEHALF OF THE
INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA

BEFORE THE
SUBCOMMITEE ON ENERGY AND AIR QUALITY
COMMITTEE ON ENERGY AND COMMERCE
U.S. HOUSE OF REPRESENTATIVES

REGARDING THE
PIPELINE INSPECTION, PROTECTION, ENFORCEMENT AND SAFETY ACT OF 2006 AND SAFETY ASSESSMENT INTERVALS FOR NATURAL GAS PIPELINES

MARCH 12, 2008

Mr. Chairman and Members of the Subcommittee:

Good morning. My name is Phil Wright, and I am President of Williams Gas Pipeline. I am testifying today on behalf of the Interstate Natural Gas Association of America (INGAA). INGAA represents the interstate and interprovincial natural gas pipeline industry in North America. INGAA's members transport over 90 percent of the natural gas consumed in the United States through a network of approximately 200,000 miles of transmission pipeline. These transmission pipelines are analogous to the interstate highway system – in other words, large capacity systems spanning multiple states or regions.

Williams is the nation's second-largest transporter of natural gas, transporting about 12 percent of the natural gas consumed in the United States. We operate three interstate pipelines which provide natural gas to major markets on both the east and west coasts including Atlanta, the Carolinas, Washington, D.C., Philadelphia, New York, Portland, Seattle and Florida. These systems total about 15,000 miles of pipe, transporting natural gas from the Gulf of Mexico, Canada, the Rocky Mountains, LNG importation terminals, and other production areas.

INDUSTRY BACKGROUND

Mr. Chairman, natural gas provides 25 percent of the energy consumed in the U.S. annually, second only to petroleum and roughly equal to coal. From home heating and cooking, to industrial processes, to power generation, natural gas is a versatile and strategically important energy resource. Looking forward, it is noteworthy that natural gas has the lowest greenhouse gas emissions of any of the fossil fuels relied on by our economy.

As a result of the regulatory restructuring of the industry during the 1980s and early 1990s, interstate natural gas pipelines no longer buy or sell natural gas. Interstate pipeline operators do not take title to the natural gas moving through our pipelines. Instead, pipeline companies sell transportation capacity much the same as a railroad, airline or trucking company.

Because the natural gas pipeline network is essentially a "just-in-time" delivery system, with limited storage capacity, customers large and small depend on reliable around-the-clock service. That is an important reason why the safe and reliable operation of our pipeline systems is so important. According to U.S. Department of Transportation data, the natural gas transmission pipelines operated by INGAA's members and by others historically have been the safest mode of transportation in the United States. The interstate pipeline industry, working cooperatively with the Pipeline and Hazardous Materials Safety Administration (PHMSA) of the U.S. Department of Transportation, is taking affirmative steps to make this valuable infrastructure even safer.

Congressional involvement in pipeline safety dates back almost 40 years to enactment of the Natural Gas Pipeline Safety Act in 1968. This legislation borrowed heavily from the engineering standards that had been developed over previous decades. The goals of this federal legislation were to ensure the consistent use of best practices for pipeline safety across the entire industry, to encourage continual improvement in safety procedures and to verify compliance. While subsequent reauthorization bills have improved upon the original, the core objectives of the federal pipeline safety law have remained a constant.

Mr. Chairman, I would like to make one important point about the future of natural gas and associated transportation infrastructure. This Committee is in the midst of exploring the parameters of legislation to mandate a reduction in U.S. greenhouse gas emissions. Given its environmental benefits, natural gas will be critical to the success of a national climate change mitigation program, especially in the first few decades. In order for natural gas to fulfill its role as the only realistic "bridge" to and critical supply of a low-carbon energy economy, the United States will need both increased natural gas supplies and the infrastructure to deliver those supplies. The supply/demand balance in the natural gas market already is tight, as reflected in the record high prices for the commodity and in price volatility.

We are witnessing the growing dependence on natural gas throughout the year – not just in the winter months – and this has implications for pipeline safety requirements; in particular, federal requirements that necessitate taking lines out of service for inspection and maintenance. We all recognize that pipeline safety and reliability are critical to public safety and to public acceptance of necessary pipeline infrastructure. Our goal is to achieve both scientifically-based safety requirements and the reliable delivery of natural gas to customers.

HOW SAFE ARE NATURAL GAS TRANSMISSION PIPELINES?

While not perfect, the safety record of natural gas transmission lines compares very well to other modes of transportation. Because natural gas pipelines are buried and isolated from the public, pipeline accidents involving fatalities and injuries are rare. And our people and our continuously improving practices are driving to eliminate them.

In 2007,[1] there was only a single general public fatality due to a natural gas transmission line accident. (This occurred in connection with an external corrosion failure on a natural gas transmission pipeline in rural Louisiana.) The other six fatalities that occurred since 2002 in connection with natural gas transmission pipeline accidents involved pipeline employees, pipeline contractors or third-party excavators working in the vicinity of pipeline facilities. Injuries resulting from incidents on natural gas transmission pipelines during 2002-2007 totaled 33. These injuries involved pipeline employees, pipeline contractors working on the pipeline facilities and third-party excavators,

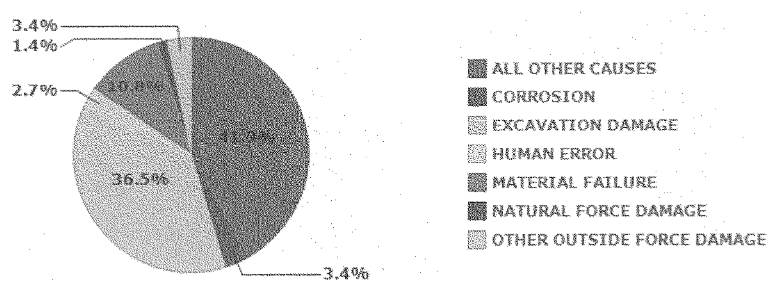
[1] http://primis.phmsa.dot.gov/comm/reports/safety/cpi.html#_ngtrans

For perspective, the natural gas transmission industry transported approximately 22 *trillion* cubic feet of natural gas in 2006, containing an energy content equal to about 2.7 times the energy output of all the nuclear power plants in the United States.[2]

In 2006, INGAA came before this Committee and recommended that PHMSA modify its data reporting criteria to reflect pipeline accident trends more accurately. At the time, PHMSA defined a "reportable incident" as one that resulted in: (1) a fatality, (2) an injury, or (3) property damage in excess of $50,000. The property damage metric skewed the data, because it was not adjusted for inflation and because it included the value of the natural gas lost in connection with the incident. As this Committee knows, natural gas commodity prices have increased significantly over the last eight years. This development, wholly unrelated to the nature of the incidents being reported to PHMSA, caused an abnormal increase in the number of "reportable accidents". Minor pipeline leaks that would not have met the threshold for a reportable incident several years ago were being reported simply due to the increased value of the natural gas lost. This provided policymakers and the public with a misleading picture of pipeline accident trends.

Beginning in 2006, PHMSA modified its accident reporting criteria and revised data back to 2002 to mitigate the effect of volatile natural gas commodity prices. Pipeline accident data now is segregated into two categories – "serious" incidents[3] and "significant" incidents[4]. "Serious" incidents are those that result in a fatality or an injury requiring in-patient hospitalization. "Significant" incidents include both "serious" incidents plus incidents that cause $50,000 in property damage (damage, repair and natural gas lost). In addition, PHMSA now indexes the components of the $50,000 property damage threshold.

Serious Incident Cause Breakdown
National, Gas Transmission, 1987-2006



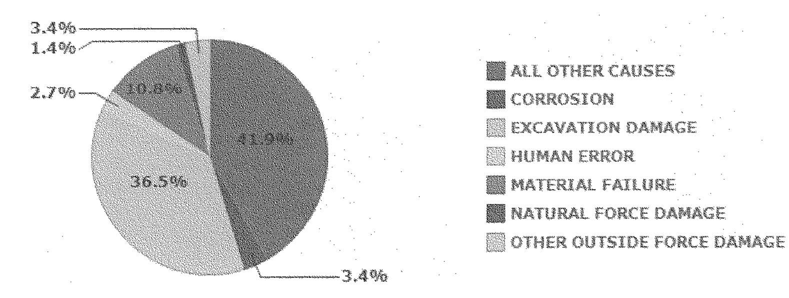
Source: PHMSA Significant Incidents Files Oct 19, 2007

[2] U.S. Energy Information Administration data for 2006.
[3] http://primis.phmsa.dot.gov/comm/reports/safety/SerPSI.html
[4] http://primis.phmsa.dot.gov/comm/reports/safety/SigPSI.html

INGAA suggests that policymakers should focus most intently on the causes of "serious" incidents – those resulting in a fatality or major injury. The chart above outlines the causes of serious incidents, and as you can see, the leading cause is excavation damage, followed by material failure and then other outside force damage (typically a vehicle collision with above-ground pipeline equipment). Corrosion causes only 3.4 percent of "serious" accidents. These statistics demonstrate clearly why excavation damage prevention has been, and will continue to be, a primary focus of the industry's safety efforts.

Now let us look at "significant" incidents involving natural gas transmission pipelines. Again, this category includes both "serious" incidents and pipeline leaks that do not result in a fatality or major injury. Given the dollar threshold that determines whether an incident is "significant", PHMSA has tracked incident costs since 2002. For example, property damage to the public (not to pipeline operators themselves) caused by "significant" incidents totaled $793,500 dollars in 2007. Corrosion is a more prominent cause of "significant" incidents than it is for "serious" incidents, second only to excavation damage. Still, corrosion accounts for only 22 percent of the total number of "significant" incidents. The integrity management program and its regimen of periodic inspections are focused almost exclusively on detecting and mitigating corrosion.

Significant Incident Cause Breakdown
National, Gas Transmission, 1987-2006



Source: PHMSA Significant Incidents Files Oct 19, 2007

Detailed incident information such as this is useful for spotting trends, correlating results with the technologies and management processes that have been implemented to improve pipeline safety, and targeting resources to areas that offer the greatest promise for achieving additional improvements in pipeline safety.

INTEGRITY MANAGEMENT PROGRAM FOR NATURAL GAS TRANSMISSION PIPELINES

The most significant provision of the Pipeline Safety Improvement Act of 2002 ("PSIA") dealt with the "Integrity Management Program" ("IMP") for natural gas transmission pipelines. Section 14 of the PSIA requires operators of natural gas transmission pipelines to: (1) identify all the segments of their pipelines located in "high consequence areas" (areas where the pipeline adjacent to significant population); (2) develop an integrity management program to reduce the risks to the public in these high consequence areas; (3) undertake structured baseline integrity assessments (inspections) of all pipeline segments located in high consequence areas (HCAs), to be completed within 10 years of enactment; (4) develop a process for repairing any anomalies[5] found as a result of these inspections; and (5) reassess these segments of pipeline every seven years thereafter, in order to verify continued pipe integrity.

The PSIA requires that these integrity inspections be performed using one of the following methods: (1) an internal inspection device (or a "smart pig"); (2) hydrostatic pressure testing (filling the pipe up with water and pressurizing it well above operating pressures to verify a safety margin); (3) direct assessment (digging up and visually inspecting sections of pipe); or (4) "other alternative methods that the Secretary of Transportation determines would provide an equal or greater level of safety." The pipeline operator is then required by regulations implementing the 2002 law to repair all non-innocuous anomalies and to adjust operation and maintenance practices to minimize "reportable incidents". Internal inspection devices are the primary means for performing integrity assessments of natural gas transmission pipelines, because these are the most versatile and efficient devices. The other assessment alternatives prescribed by the law are useful when smart pig technology cannot be effectively used. A drawback associated with these other alternatives is that they require a pipeline to cease or significantly curtail natural gas delivery operations for periods of time or require extensive excavation of the pipeline.

The natural gas pipeline industry was one of the inventors of internal inspection "smart pig" devices decades ago, and the capabilities and effectiveness of these devices as analytical tools has increased steadily. Still, the pipeline industry must address some practical issues in order to utilize these devices more fully.

First, only the newest pipelines were engineered to accept such inspection devices. Prior to this, pipelines often were built with tight pipe bends, non-full pipe diameter valves, continuous sections of pipe with varying diameters, and side lateral piping. Such pipeline systems need to be modified to allow the use of internal inspection devices.

The other practical issue is modifying pipelines to launch and receive internal inspection devices. Since a pipeline is buried underground for virtually its entire length, the installation of aboveground pig launchers and receivers usually is done at or near other

[5] An anomaly is defined as a possible precursor to a future incident.

above ground locations, such as compressor stations. Compressor stations typically are spaced 75 to 100 miles apart. Therefore, a separate set of launchers and receivers must be installed for every segment between compressors and occasionally new sites must be acquired for these pigging facilities.

The natural gas pipeline industry will use hydrostatic pressure testing and direct assessment for segments of transmission pipeline that cannot be modified effectively to accommodate smart pigs, or in other special circumstances. There are issues associated with both hydrostatic pressure testing and direct assessment technology.

In the case of hydrostatic pressure testing, an entire section of pipeline must be taken out of service for an extended period of time, limiting the ability to deliver gas to downstream customers and potentially causing market disruptions as a result. In addition, hydrostatic testing – filling a pipeline up with water at great pressure to see if the pipe fails – is a potentially destructive testing method that must take into account pipeline characteristics so that it does not exacerbate some conditions while resolving others.

Direct assessment (DA) is generally defined as an inspection method in which sections of pipe are excavated and visually inspected at intervals along the right-of-way based on sophisticated above ground electrical surveys that identify potential problem areas for further examination. The amount of excavation and subsequent disturbance of landowner's property involved with this technology is significant, and the level of disturbance does not decrease with future reassessments of the same section of pipe. The disturbance to other infrastructure, including roads and other utilities, caused by direct assessment also creates some level of risk and inconvenience for the public.

While pipeline modifications and inspection activity generally follow a pre-arranged schedule, repair and mitigation work is unpredictable. A pipeline operator does not know, ahead of time, how many anomalies an inspection will find, how severe such anomalies will be, or how quickly they will need to be repaired. Repair work often requires systems to be shut down, even if the original inspection work did not affect system operations.

Baseline integrity assessments – the type of work in which our industry now is engaged – are an effective means of identifying corrosion problems and any material defects that were not discovered when a pipeline was constructed. While material defects are less common, they are essentially eliminated for the life of the pipeline once they are identified and repaired. Corrosion is an on-going phenomenon that is managed and controlled utilizing many techniques. Periodic reassessments are an effective method for identifying whether corrosion prevention systems are adequately preventing this "time-dependent" deterioration.

INTEGRITY MANAGEMENT PROGRESS TO DATE

Based on data for the first half of the IMP inspection baseline period, there is ample basis for concluding that our pipelines are safe and that they are becoming safer by removing the possible precursors to future incidents. It also is clear that the industry is dutifully implementing the IMP program prescribed by Congress. For example, all INGAA member companies have been subject to in-depth IMP audits by PHMSA to assure that the programs are comprehensive and implemented consistently.

PHMSA has reported[6] on IMP progress achieved through the end of 2006. (Comprehensive 2007 industry data will not be available publically until April) Consequently, we will rely on data from a survey of INGAA member companies to illustrate trends through 2007.

The following statistics will help put this reported data in perspective. First, there are approximately 293,950 miles of gas transmission pipeline in the United States. INGAA's member companies account for approximately 200,000 miles (or about two-thirds) of this total, with the remainder being owned by *intra*state transmission systems or Local Distribution Companies (LDC). The INGAA IMP survey results cover 191,041 miles, which includes over 95 percent of the total mileage owned by INGAA member companies. Second, there are approximately 19,950 miles of transmission pipeline in HCAs (i.e., mileage subject to gas integrity rule). This represents about 6.5 percent of total natural gas transmission pipeline mileage in the United States.

The INGAA IMP survey results reflect 9,051 miles or roughly 45 percent of total pipeline mileage in HCAs in the United States. It should be noted that the majority of HCA mileage (more than 10,000 miles) is owned by *intra*state pipeline and local distribution companies, which makes sense because these operators tend to have facilities located closer to populated areas. The INGAA survey does not include data on these pipeline systems.

INGAA HCA Pipeline Miles Inspected to Date –

- Based on INGAA IMP survey results, over 4,847 miles have been inspected through 2007, which exceeds the Congressional requirement of 50 percent of the baseline being assessed by December 2007 by 1 percent.

Additional INGAA Pipeline Miles Inspected (non-HCA pipeline) –

- Based on INGAA IMP survey results, an additional 41,335 miles of pipeline not located in HCAs has been assessed and repaired utilizing the same methodologies.

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6 http://primis.phmsa.dot.gov/gasimp/PerformanceMeasures.htm

Rightly, the PSIA prioritized the inspection of pipelines operating in HCAs. Still, as a practical matter, the resources and effort required to obtain inspection data for HCAs has resulted in the inspection of total pipeline mileage that exceeds the HCA mileage by several multiples. Here is why this has occurred.

The vast majority of the assessments to date have been completed using smart pig devices. As discussed, these devices are launched and received at above ground locations that typically coincide with the location of compressor stations. Therefore, even if a 100-mile pipeline segment contains only five miles of HCA, it is necessary to assess the entire 100-mile segment between compressor stations. This results in significant "over-testing" on our systems. Any problems identified by these inspections, whether in an HCA or not, are remediated.

As you can see from the data, only about seven percent of total gas transmission pipeline mileage is located in HCAs. Yet, due to the over-testing situation, we anticipate that about 55 to 60 percent of total natural gas transmission pipeline mileage actually will be inspected during the 10-year IMP baseline period.

Now let us look at what the IMP integrity inspections have found to date. For this data, we focus on filed information from HCA segments, since these are the segments specifically covered under the integrity management program and reported to PHMSA.

There have not been any "serious incidents" due to time-dependent causes (i.e., corrosion) in natural gas transmission pipeline segments within HCAs since the reporting of such data to PHMSA began in 2002. Even before that, there was no history of "serious" natural gas pipeline incidents in high population density areas due to time-dependent causes. This likely is attributable to the industry practices that have made such events a remote probability and the additional regulatory requirements for high density areas that have been part of the federal pipeline safety regulations (for natural gas transmission pipelines) since 1970.

The number of "reportable incidents" for all causes (and just time-dependent causes) for all HCAs and separately for the mileage that INGAA members operate is as follows:

Year	All Gas Transmission Reportable Incidents in HCAs	INGAA Reportable Incidents in HCAs
2004	9 (2)	3 (0)
2005	10 (0)	3 (0)
2006	11 (1)	2 (0)
2007	Data Not Yet Available	4 (0)
Miles Reported	19,950 miles	9,051 miles

We highlight the time-dependent defects in the data for these incidents, because these are the types of defects that are the prime target of reassessment under the integrity management program. By time-dependent, we mean problems with the pipeline that develop and grow over time, and, therefore, should be examined on a periodic basis. The most prevalent time-dependent defect is corrosion; therefore, the IMP reassessment effort is focused most intently on corrosion identification and mitigation.

Most reportable incidents caused by excavation damage (more than 85 percent) result in an immediate pipeline failure, so periodic IMP assessments are unlikely to reduce these types of accidents in any significant way. Assessments on a periodic schedule are, therefore, most effective for managing time-dependent anomalies such as corrosion.

One of the primary reasons for the IMP program is to discover and repair anomalies that may lead to a future incident. The IMP baseline inspection program is discovering the isolated anomalies that have grown since pipelines were put in service, despite the extensive corrosion prevention systems. In most cases, these pipelines have operated, and will continue to operate, incident free for many decades.

We have identified the number of "immediate" and "scheduled" repairs that have been generated by the IMP inspections thus far. These are anomalies in pipelines that have not resulted in an incident, but are repaired as a precautionary measure. "Immediate repairs" and "scheduled repairs" are defined terms under both PHMSA regulations and engineering consensus standards. As the name suggests, immediate repairs require immediate action by the operator, due to a higher probability of a reportable incident or leak in the future. Scheduled repair situations are those that require repair within a longer time period because of their lower probability of failure.

The number of "immediate" repairs (repair within five days of discovery) of anomalies found in HCAs performed by all gas transmission operators and performed by INGAA members alone is as follows:

Year	All Gas Transmission "Immediate" Repairs in HCAs	INGAA "Immediate" Repairs in HCAs
2004	104	34
2005	261	48
2006	157	21
2007	Not Available Yet	39
HCA Mileage Inspected to Date	10,396	4847

The number of "scheduled repairs" (repair generally within one year of discovery) of anomalies found in HCAs by inspections is as follows:

Year	All Gas Transmission "Scheduled" Repairs in HCAs	INGAA "Scheduled" Repairs in HCAs
2004	599	133
2005	378	67
2006	338	54
2007	Not Available Yet	55
HCA Mileage Inspected to Date	10,396	4847

While we are only halfway through the baseline assessment period, the results support favorable conclusions about the integrity of the gas transmission pipeline system, the effectiveness of maintenance practices undertaken by individual pipeline operators, the earlier regulatory requirements of PHMSA, and the additive value of the new IMP. "Immediate" repairs in HCAs have removed 2.9 anomalies per every 100 pipeline miles of inspected HCA pipe. "Scheduled" repairs have removed an additional 6.4 anomalies per 100 miles of inspected HCA pipe. By completing these "immediate" and "scheduled" repairs in a timely fashion, the pipeline industry has reduced significantly the possibility of future incidents due to corrosion.

As "immediate" and "scheduled" time-dependent precursors are found and repaired during the baseline period, we expect the number of time-dependent significant incidents in HCA areas to approach zero, because the gestation period for these anomalies to grow to failure is significantly longer than the present or proposed risk based re-assessment interval.

It is worth emphasizing that data from operators who have completed more than one such periodic integrity assessment over a number of years strongly suggests a dramatic decrease in the occurrence of time-dependent precursors requiring repairs the second time around. Technical analysis undertaken in 2005 by the Pipeline Research Council International (PRCI)[7], an international standards-setting and research group, demonstrated a significant reduction in the number of serious anomalies found during risk-based reassessments, suggesting that baseline assessments using smart pig technology are extremely effective in identifying potential problems before they manifest themselves into safety risks. This research report also reconfirms the detailed recommendations for setting the risk-based interval contained in the American Society of Mechanical Engineers consensus standard ASME B31.8S.

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[7] *Integrity Management Reinspection Intervals Evaluation*, Pipeline Research Council International, Inc., December 2005

One important benefit of the integrity management program is verifying and re-certifying the safety of older pipeline systems. Many of the gas pipelines being inspected under this IMP are 50 to 60 years old. While it is often hard for non-engineers to accept, well-maintained natural gas transmission pipelines can operate safely for many decades. Natural gas transmission pipelines are built to be robust and are not subject to the same operational stresses as vehicles. Much of the inspection data highlighted in the research comes from pipelines that were built in the 1940s and 1950s. And yet, after all these years, the number of anomalies found on a per-mile basis is low. Once these anomalies are repaired, the "clock can be reset," and these pipelines can operate safely and reliably for many additional decades.

SEVEN-YEAR REASSESSMENT INTERVAL

Under the PSIA, gas transmission pipeline operators have 10 years within which to conduct baseline integrity assessments on all pipeline segments located in HCAs. Operators also are required by law to begin reassessing previously-inspected pipe seven years after the initial baseline and every seven years thereafter. PHMSA has interpreted these requirements to mean that, for segments baseline-inspected in 2003 through 2005 (including those for which a prior assessment is relied upon), reassessments must be done in years 2010 through 2012 – *even though baseline inspections are still being conducted.*

In 2001, INGAA provided Congress with a proposed industry consensus standard on reassessment intervals that had been developed by the ASME. The ASME B31.8S consensus engineering standard used several criteria to determine a reassessment interval for a particular segment of pipe, such as the operating pressure of a pipe relative to its strength and the type of inspection technique used. This risk-based standard utilized a "decision matrix" based on detailed engineering analysis of basic corrosion mechanisms, correlation with over 30 years of inline smart pig inspection results, more than 60 years of operational and performance data of natural gas transmission pipelines utilizing corrosion prevention practices and actual pipeline incident reports.

The ASME standard proposes a conservative 10-year reassessment interval for typical natural gas transmission pipelines operating at high pressure, which represent most of the gas transmission pipeline mileage. The standard suggested longer inspection intervals for lower pressure lines, which represent a lower risk and a smaller portion of the gas transmission pipeline mileage. The standard also suggested <u>shorter</u> intervals for pipeline segments operating in higher-risk environments, including environments where unusually aggressive corrosion would be more likely to occur.

Why is INGAA so concerned about the seven-year reassessment interval? First, there is the "overlap" of baseline inspections and reassessments in years 2010 through 2012. The ability to meet the required volume of inspections is daunting given the limited number of inspection contractors and equipment available. In addition, this stepped up level of inspection activity would be difficult to accommodate without affecting gas system deliverability. This last point is critical. Some assume that we are focusing on the re-assessment interval only because of the costs to industry. In fact, our costs will be modest compared to the potential costs to consumers in the form of higher natural gas commodity prices if pipeline capacity becomes too constrained due to the level of simultaneous inspection activity. Some regions of the country can handle more frequent reductions in pipeline deliverability, due to the volume of pipeline capacity serving those regions. The Chicago region and the Gulf Coast, for example, are equipped to handle frequent pipeline capacity interruptions due to the abundance of pipeline capacity in those regions. Other regions, such as the Northeast, New England, Florida, California and the Pacific Northwest, face greater risk that gas commodity prices will be affected if pipeline capacity is reduced too often. These downstream market effects should be considered carefully, especially during the baseline inspection period when pipeline modifications (to accommodate inspection equipment), inspections, and repair work will be at peak levels.

Some also suggest that, if the pipeline industry is technically capable of inspecting its lines for corrosion more frequently than engineering standards suggest, then it should do so and not worry about the costs or the logistics. Yes, large interstate pipelines could, in fact, be inspected more frequently than every seven years, especially once systems have been modified to accommodate smart pig devices. Still, just because pipelines can be inspected more often, does not make it rational to require a very conservative one-size-fits-all inspection policy. Most automobile manufacturers recommend oil changes every 3000 miles and only every 10,000 miles for some newer technology cars. While Congress could instead mandate that all vehicle owners change their oil every 1000 miles, there would be little, if any, additional benefit from more frequent oil changes, and the cost would take divert owners' money away from other, more beneficial maintenance activities.

The Integrity Management Program requires industry to identify and mitigate risks to the public associated with operating its facilities. Inspections are only one tool for achieving that end, and are not a tool that singlehandedly can accomplish all of the required goals of the program. As previously discussed, corrosion is the primary focus of the reassessments undertaken pursuant to the Integrity Management Program. Corrosion causes about 22 percent of the "significant" failures on gas transmission lines, and only 3.4 percent of the failures that result in "serious" incidents.

It is vital that an effective integrity management program utilize a risk-based approach to focus attention and resources, and that this program include strategies to address all risks. This would suggest that a shift in focus from the lowest cause of incidents to the highest is warranted.

RECOMMENDATION FROM GAO

Fortunately Mr. Chairman, you do not have to make a decision on this reassessment question based upon INGAA's recommendation alone. When Congress enacted the PSIA in 2002, it required the Government Accountability Office (GAO) to conduct an analysis of natural gas pipeline reassessment intervals and report back to Congress with any recommended changes to the seven-year requirement. The title of the GAO report, completed in September of 2006 (GAO-06-945), sums up its conclusion – "Natural Gas Pipeline Safety: Risk-Based Standards Should Allow Operators to Better Tailor Reassessments to Pipeline Threats." This title also concisely states INGAA's position on integrity assessments and on pipeline safety activities in general. That is, safety programs and activities should be based upon a reasoned determination of the risks to the public, with procedures focused upon reducing those risks to the greatest extent possible.

The current seven-year reassessment interval mandate requires natural gas transmission operators to focus inordinate resources on areas that present relatively low risk to the public, especially once the baseline integrity reassessments are completed and identified problems are repaired. To quote the GAO report:

> *To better align reassessments with safety risks, the Congress should consider amending section 14 of the Pipeline Safety Improvement Act of 2002 to permit pipeline operators to reassess their gas transmission pipeline segments at intervals based on technical data, risk factors, and engineering analyses. Such a revision would allow PHMSA to establish maximum reassessment intervals, and to require short reassessment intervals as conditions warrant.*

SPECIAL PERMITS AND RECOMMENDATION FROM DOT

The Department of Transportation has agreed with INGAA on the importance of risk-based reassessment intervals, and the challenges presented by the current one-size-fits-all approach. During the 2006 debate on the Pipeline Inspection, Protection, Enforcement, and Safety (PIPES) Act, several members of the Senate expressed concern about modifying the seven-year requirement, but suggested instead that PHMSA could waive the seven-year reassessment interval, where justified, based on the Pipeline Safety Act's existing waiver authority. The PHMSA Administrator at the time, Adm. Thomas Barrett, confirmed that PHMSA had adequate waiver authority, but expressed a preference for Congress amending the statute to allow specifically for risk-based intervals. Congress ultimately retained the seven-year interval, but pursuant to the PIPES Act did require PHMSA to make a recommendation to Congress on a statutory change regarding reassessment intervals.

Pending Congressional action on removing the seven-year requirement, PHMSA has initiated a "special permit" process that would, in effect, allow for longer reassessment intervals when technically justified. PHMSA proposed a "special permit" process for risk based inspection intervals at a Technical Pipeline Safety Standards Committee (an advisory committee to PHMSA) meeting in December. The response to the proposed IMP special permit process from governmental, public and industry participants generally was very positive.

While INGAA certainly supports the "special permits" process, we remain convinced that the best course is for Congress to repeal the seven-year requirement and to authorize PHMSA specifically to adopt rules governing risk-based determinations. The "special permits" process likely will be confined to individual waivers, a "one-off" process that likely will be administratively cumbersome and resource-intensive for both the regulator and the industry. We also have concerns that a case-by-case waiver process could result in inconsistent results for pipeline facilities and pipeline owners that otherwise are operating under very similar circumstances.

This is why we urge Congress to consider seriously the recommendation made by Deputy Secretary of Transportation Adm. Thomas Barrett, dated November 27, 2007. Adm. Barrett outlined the numerous reasons why the seven-year requirement is illogical under most circumstances, and how this requirement could present gas deliverability problems unless changed (or unless PHMSA waives the requirements in most cases). His letter to Congress cited the GAO recommendation as well and urged Congress to authorize "DOT to establish rules setting risk-based intervals for reassessment of natural gas transmission pipelines." Adm. Barrett's letter included a list of technically-based criteria PHMSA would use in determining what an appropriate reassessment interval would be for each pipeline segment. He also included proposed statutory language consistent with the GAO recommendation.

INGAA strongly endorses this statutory change. We believe a clear statutory mandate from Congress authorizing the adoption of risk-based intervals would lead to a more efficient allocation of PHMSA resources and greater consistency for the industry.

DAMAGE PREVENTION AND WORKING WITH COMMUNITIES

The "serious" incident data cited earlier in my testimony points to the importance of damage prevention as a means to avoid fatalities and injuries. The PIPES Act took an important step forward by creating incentives for states to adopt improved damage prevention programs that meet nine critical elements. INGAA was pleased to join last year with the American Gas Association, the Association of Oil Pipelines, American Petroleum Institute, the Associated General Contractors and the National Utility Contractors Association in creating the Excavation Damage Prevention Initiative (EDPI). The purpose of the EDPI was to provide general guidance for states on how they can meet the nine elements articulated by Congress in 2006, in order to create a more consistent process for evaluating state programs prior to receiving federal grant dollars. Working together, the members of the EPDI developed a "roadmap" for states to follow in developing damage prevention programs that meet the goals outlines in the PIPES Act. We hope this roadmap will be used by the states, and by DOT, in determining which programs are worthy of state grant funds.

Our regulator and our industry are tackling the difficult and multi-faceted issue of excavation damage prevention. For example, following up on its commitment made during the 2006 PIPES Act debate, PHMSA encouraged my own company to participate in a pilot of the "Adopt-A-Community" program. We have embraced this challenge. Our approach integrates new GPS technology with a focused local community solution. Williams and the Virginia Utility Protection Service have joined in an effort to:

- Explore the needs of state and local agencies and authorities in order to take the initiative on reducing the risk of excavation damage on underground facilities.
- Enhance community awareness and exchange ideas to protect pipeline facilities from encroachment and thus improve public safety.
- Deploy newly available GPS and geo-coding technology to minimize mistakes in communications between pipeline operators, one-call system operators and prospective excavators.
- Integrate available databases to enhance planning and sharing of land use information among underground facility operators and public safety stakeholders.

While this effort focuses on just one part of improving the excavation damage prevention system, we feel it is an important contribution that can be replicated throughout the United States.

PIPELINE SAFETY USER FEES

For several decades, the federal pipeline safety program has been funded almost exclusively through industry user fees. The law that authorized the user fee program for pipeline safety activities (P.L. 99-272, 49 USC 60301) limited the collection of such fees to hazardous liquid and natural gas **transmission** pipeline operators and LNG terminal owners. This limitation made sense at that time, because the federal pipeline safety program then focused almost exclusively on the regulation of interstate transmission pipelines and LNG terminals.

This now has changed, because the PIPES Act both created a new "distribution integrity management program," and increased the potential state government matching grants (which fund state-related pipeline safety programs focused on gas distribution and intrastate pipeline oversight) from the original "up to 50 percent" of state budgets to "up to 80 percent" of state budgets. The new law has greatly expanded the scope of PHMSA activity associated with natural gas distribution pipelines and has increased the potential level of federal financial support for state activities associated with gas distribution pipelines. Yet, due to the prohibition in the current law, natural gas distribution pipelines pay no federal user fees to support these activities.

The current statutory limitation compels natural gas and hazardous liquid transmission pipelines to support regulatory programs that benefit a segment of the industry that is not paying its fair share. It seems fundamental that, if government programs are to be funded using a user fee structure, then the actual users of such programs should be expected to pay their fair share of such costs.

There is no reason to believe that assessing federal user fees on distribution pipelines will have any adverse effect on state programs, contrary to the assertions that have been made by some. It also is not unprecedented to have pipelines pay both federal and state user fees. For example, interstate pipelines with facilities located in those states that participate in the oversight of interstate pipelines pay both a federal user fee and a state user fee. There is no reason why distribution pipeline operators cannot do the same.

Distribution pipeline operators also have suggested that transmission pipelines should continue to pick up the costs for these distribution-related safety activities, and then attempt to recover such costs in the rates charged to distribution pipeline companies. This argument fails to acknowledge that many natural gas transmission pipeline customers do not pay the maximum FERC-approved rate that would allow for full recovery of such costs. Pipeline customers have, for years, demanded discounts from the FERC-approved rate where competitive situations allow for choice among pipeline services. The large volume of discounted pipeline transactions means that pipelines are not guaranteed to recover all of their FERC-approved costs in competitive environment. Natural gas distribution companies often are the beneficiaries of this discounting.

It is entirely reasonable to ask that each segment of the pipeline industry pay for its fair share of the federal pipeline safety program. We hope Congress will address this disparity by authorizing PHMSA to collect pipeline safety user fees from natural gas distribution companies.

CONCLUSION

Mr. Chairman, INGAA and its members have worked in good faith since 2001 to convince Congress that a risk-based solution for determining reassessment intervals is the best alternative from a public safety standpoint. Since then, both GAO and the DOT have analyzed this issue and have joined with INGAA in recommending to Congress that the inflexible seven-year requirement be repealed in favor of risk-based standards. In the 40 years since the Natural Gas Pipeline Safety Act was enacted, this likely is the single pipeline safety issue that has received the greatest analysis. All of the reasoned analysis points in one direction. We believe that the burden of proof has been met, and therefore urge you and the Committee to enact the statutory change recommended by DOT and GAO.

Thank you for agreeing to conduct this hearing, and for inviting me to participate today. Please let us know if you have any additional questions, or need additional information.

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Summary of Testimony:

The Interstate Natural Gas Association of America (INGAA) represents virtually all the natural gas pipeline companies in the U.S. and Canada. Our industry has a long history of safe operation, but we are always looking for ways to reduce accidents associated with our pipelines.

The Pipeline Safety Improvement Act of 2002 (PSIA) created the Integrity Management Program for natural gas transmission pipelines as a way to verify the safety of our systems, identify potential problems, and mitigate any identified safety risks in a timely manner. The PSIA requires all pipeline segments located in populated areas to have a baseline integrity assessment within ten years of enactment (December 2012), and periodic reassessments every seven years. The INGAA member companies are on-track for assessing all of the pipeline segments covered under the program within the 10-year baseline.

Going forward, INGAA believes that reassessment intervals should be established for each pipeline segment using a risk-based approach to determine the appropriate timeframe. Both the GAO and DOT have determined that the current seven-year reassessment requirement is "too conservative," and forces pipeline operators to expend time and resources in a manner which does not provide the best level of safety to the public. To quote the title of the GAO report: "Risk-Based Standards Should Allow Operators to Better Tailor Reassessments to Pipeline Threats." We urge Congress to modify the statute to reflect the recommendations from GAO and DOT.

Looking at the most significant safety risks for our pipelines, INGAA supports improved state damage prevention programs. Williams is undertaking a voluntary effort, in conjunction with PHMSA, to establish a pilot program for educating local communities on pipeline safety issues, and taking action to reduce to probability of pipeline accidents.

INGAA also urges Congress to amend the pipeline safety statute to allow PHMSA to collect pipeline safety user fees directly from all program users, including natural gas distribution companies.

We thank the Subcommittee for the opportunity to testify.

Mr. WYNN. Thank you for your testimony. Mr. Kessler.

STATEMENT OF RICK KESSLER, BOARD MEMBER, PIPELINE SAFETY TRUST

Mr. KESSLER. Thank you, Mr. Chairman. And I just want to say thanks to Chairman Dingell and Chairman Upton—or rather, Chairman Boucher— for their wonderful introduction earlier. Good morning and thank you for allowing me the honor of testifying before what I think is the best committee in Congress. And for the record my name is Rick Kessler, and as some of you know I had the great fortune of staffing this subcommittee for a number of years, beginning in the mid 1990s, on the issue of pipeline safety.

But I am here today as a member of the Board of Directors of the nonpartisan, nonprofit Pipeline Safety Trust. The Trust came into being after the 1999 Olympic pipeline tragedy in Bellingham, Washington that left three young people dead, devastated a local salmon stream and caused millions of dollars of economic disruption. The Trust is the Nation's only nonprofit organization to provide the voice for those affected by pipelines who otherwise would have none, including those who have died in pipeline accidents.

Our vision is simple: communities should feel safe when pipelines run through them and trust that their government is proactively working to prevent pipeline hazards. We believe that local communities who have the most to lose if pipelines fail should be included in discussions of how best to prevent pipeline accidents. Only when trusted partnerships between pipeline companies, government, communities and safety advocates are formed will pipelines truly be safer.

Because time is short and because a lot of ground in my written testimony has been covered, I want to provide a very condensed summary of our written testimony and focus a bit more intently on the reassessment interval for natural gas transmission pipelines.

The bottom line is the trust believes it is critical, absolutely critical, to maintain the 7 year reassessment interval that this committee and Congress mandated as a backstop in 2002 and again reaffirmed in 2006. We believe PHMSA's proposed waiver process appears to be technically sound and we believe that providing extensions of the reinspection period are most appropriately done on a case-by-case basis; however, because this is a resource-intensive process the assessment of fees for waiver processing should be considered to ensure that PHMSA's ability to carry out its primary mission, its primary mission of ensuring pipeline safety, is not harmed.

What I want to also add to that is there has been some talk as if the 7 year provision is somehow arbitrary and that there is not a risk-based program, actually the program currently underway is risk-based, the 7 year interval there is a 10 year interval that was the baseline performance, the 7 year is a backstop that this committee and Congress under Chairman Tozan put in place because the purely risk-based assessment was not getting the job done.

I would remind everyone that prior to 1996 the requirement that was never carried out by DOT was for a 2 year reinspection period and in 2002 the Senate again in a deal cut by, I believe, then Senator Corzine and Senator John McCain was for a 5 year baseline and 5 year reinspection period. This committee came back with a 10 year baseline and a 7 year reinspection period that included a waiver, which is in the statute, that allows for extensions based upon other things. I think it was Mr. Matheson who was talking about the need to keep product flowing, so that was all thought out by this committee and included in the original provision.

I think, rather than spending time debating industry's concern about the duration of a reassessment period that really has yet to even kick in, we believe the Nation's safety efforts should be focused on addressing critical public safety, environmental protection, and public information provisions of the law that have yet to be implemented, including PHMSA's failure to move forward on establishing the Pipeline Safety Information Grant Program. The committee, led now by Chairman Boucher, created that program in the '02 act and strongly reaffirmed its support again in the '06 act.

I am glad to hear today that PHMSA is, after all this time, moving forward, though the brief glance I got of their proposal does raise some concerns, and I am glad Chairman Boucher asked for some time to consult on that.

I actually think these grants would allow members of the public to hire independent experts to explain, analyze, and interpret technical data, thereby actually promoting better decisions and increasing meaningful communication between diverse members of the public, governmental decisionmakers, and the pipeline industry. Ultimately, the program would help pipeline operators at PHMSA as much as the public. Congress must ensure that the program is established and fully funded.

We have mentioned a number of deadlines that PHMSA has failed to miss and we just point out that this is, has historically been the case and that is why I know a number of you are concerned because of the trend and I just want to also kind of sum up.

Oh, I also want to mention the deadline for excess flow valves which is coming up on June 1, 2008. The National Transportation Safety Board has studied and recommended the use of EFVs for years and millions of them are successfully used today. Firefighters nationwide promote the use and Congress has mandated their use. We urge the committee to keep a close eye on the upcoming deadline and to assure that we move past the study to just stalling tactics of the past and onward to the nationwide use of these important safety devices.

To wrap up, I just want to highlight some successes we have witnessed since passage of the act. PHMSA has made great strides in carrying out enforcement transparency under pipes, the stakeholder communications Web site is a huge improvement and we appreciate the success in making pipeline mapping system available again. I also want to congratulate them on the implementation of the National 811 One Call number, which then Chairman Barton and our former colleague Chris John led the way, along with the rest of you in implementing. Thank you very much and again, it is a great honor to be before you.

[The prepared statement of Rick Kessler follows:]

STATEMENT OF RICK KESSLER

Mr. Chairman and Members of the Committee:

Good morning, and thank you for inviting me to speak today on the important subject of pipeline safety. My name is Rick Kessler and I am testifying today as a member of the Board of Directors of the Pipeline Safety Trust. As many of you know, I had the great fortune of staffing this subcommittee in the area of pipeline safety for a number of years. Additionally, Pipeline Safety Trust staff are members of the Pipeline and Hazardous Materials Safety Administration's (PHMSA's) Technical Hazardous Liquid Pipeline Safety Standards Committee, chair of the Governor-appointed Washington State Citizens Committee on Pipeline Safety, and on the steering committee for PHMSA's Pipeline and Informed Planning Alliance. This testimony was prepared by the Executive Director of the Pipeline Safety Trust Carl Weimer, me, and one of the Pipeline Safety Trust's technical consultants, Lois Epstein, P.E., who previously served on the Technical Hazardous Liquid Pipeline Safety Standards Committee representing the public.

The Pipeline Safety Trust came into being after the 1999 Olympic Pipe Line tragedy in Bellingham, Washington that left three young people dead, wiped out every living thing in a beautiful salmon stream, and caused millions of dollars of economic disruption. After investigating this tragedy, the U.S. Department of Justice (DOJ) recognized the need for an independent organization that would provide informed comment and advice to both pipeline companies and government regulators, and would provide the public with an independent clearinghouse of pipeline safety information. The federal trial court agreed with the DOJ's recommendation and awarded the Pipeline Safety Trust $4 million which was used as an initial endowment for the long-term continuation of the Trust's mission.

The vision of the Pipeline Safety Trust is simple. We believe that communities should feel safe when pipelines run through them, and trust that their government is proactively working to prevent pipeline hazards. We believe that local communities who have the most to lose if a pipeline fails should be included in discussions of how best to prevent pipeline failures. And we believe that only when trusted partnerships between pipeline companies, government, communities, and safety advocates are formed, will pipelines truly be safer.

The Pipeline Safety Trust is the only non-profit organization in the country that strives to provide a voice for those affected by pipelines that normally have no voice at proceedings like this. With that in mind, we are here to speak today for those who have been tragically affected by pipeline incidents since the Pipeline Inspection, Protection, and Enforcement Act of 2006 (PIPES) passed. We are speaking for the relatives of Maddie and Naquandra Mitchel who died in the November 2007 Dixie Pipeline propane explosion in Mississippi, which also destroyed many homes and scorched 150 acres of forest. We are speaking for the family of Corbin Fawcett who was killed driving down an interstate highway in Louisiana when the Columbia Gas Transmission pipeline under that highway exploded in December 2007. We also are speaking for the six members of the general public who were killed in distribution pipeline explosions in 2007, and for all those affected by the more than $110 million in property damage caused by pipeline incidents in 2007, not to mention the millions of dollars in uncalculated costs from fuel price increases when these pipelines are temporarily shut down because of failures. Last, we are speaking on behalf of the land and water and wildlife that has been contaminated or otherwise impacted as a result of oil pipeline releases since passage of the law.

The Pipeline Safety Trust's staff and volunteers have testified before Congress nine times since the Bellingham tragedy. We have brought forward and worked with others on many initiatives that have been put into law through the Pipeline Safety Improvement Act of 2002 and PIPES. In the past 7 years, we have developed valuable working relationships with many key staff members of PHMSA, the pipeline industry, local government, and citizens nationwide.

REVIEW OF THE IMPLEMENTATION OF THE PIPELINE INSPECTION, PROTECTION, ENFORCEMENT AND SAFETY ACT OF 2006

It has been a little over 14 months since Congress enacted PIPES, so we appreciate the committee holding this hearing to review the successes and failures of PHMSA's efforts to implement many of the important safety improvements contained in the act. The Pipeline Safety Trust has been actively involved with many of these initiatives, and we are pleased to provide you with the following overview of our perspective on implementation of the PIPES Act to date.

In several instances noted below, PHMSA has missed deadlines contained in PIPES. Congress and the public deserve an explanation of why deadlines are missed. The Trust has supported every deadline that Congress has imposed and we encourage deadlines as a way to force safety improvements to move forward, but we also recognize that it is sometimes better to do things right instead of doing them fast.

REASSESSMENT INTERVALS FOR NATURAL GAS TRANSMISSION PIPELINES

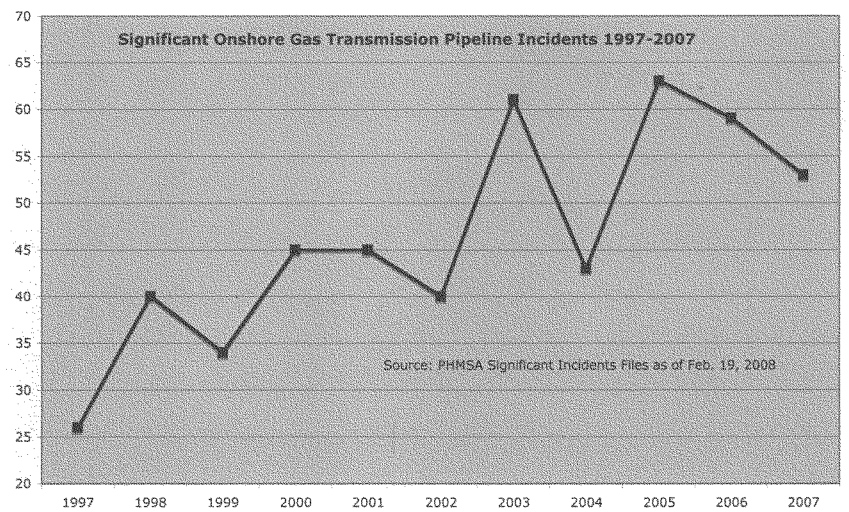
Ever since the passage of the Pipeline Safety Improvement Act of 2002, the natural gas pipeline industry has argued that the reassessment interval for gas transmission pipelines was not based on well-considered engineering and scientific data. Industry argues that each pipeline has its own unique properties and, as such, each pipeline should have reassessment intervals based on its own particular engineering and data. While we agree that the initial interval was not based on any exhaustive study or data, it also is clear that the data needed to make such a determination were not yet available. The integrity management process in the 2002 act was the needed, comprehensive start to collect such specific data from specific pipelines. Congress gave the industry ten years to complete the initial baseline integrity management survey, and we have only recently passed the date where the industry was to have completed 50% of that baseline task.

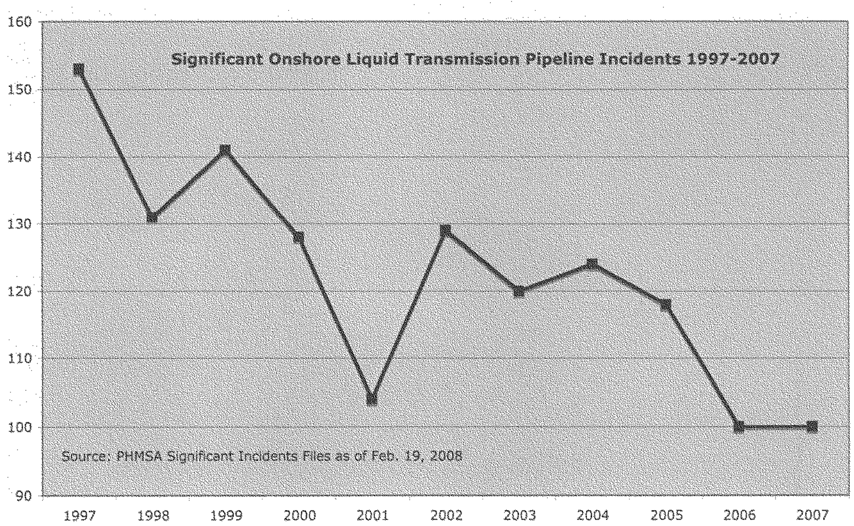
PHMSA and the industry have begun a process to provide companies that have successfully completed the initial baseline assessments for segments of their pipelines a way to apply for waivers from the current Congressionally-mandated reassessment interval. The Trust's review of this process by our technical consultants has concluded that the process is reasonable, technically-sound and well thought-out, albeit resource-intensive on the part of PHMSA. The proposed process provides significant safety protections, including an analysis by PHMSA that the public can comment on. We ask Congress to maintain the Congressionally-mandated reassessment interval to ensure a thorough review by PHMSA of waiver requests and knowledge by the public of pipeline-specific deviances from the mandated reassessment interval.

Since no rule for the waiver process has been drafted for review, the Trust wants to provide PHMSA and Congress with a list of the things we believe need to be clearly spelled out in the proposed waiver process:

- Waivers should not be processed if PHMSA does not have the resources to do so without undermining its existing pipeline safety programs. If these waivers are a priority of the industry, then Congress should consider implementing fees for waiver applications to provide PHMSA with the resources to get the job done.
- Waivers should only be considered for pipeline segments that have fully completed their initial baseline assessment, and must not be considered for those operators using Direct Assessment.
- Waivers should only be considered for pipeline segments where operators have provided PHMSA with sufficient information to show that the baseline assessment was adequate, and that they have identified the pertinent threats and have a plan in place to correctly monitor and address those threats.
- Waivers should not be considered for pipeline segments where failures have occurred within the past ten years from causes within operators' primary responsibility (corrosion, material failures, incorrect operation, etc.).
- Waivers should not be considered for pipeline segments that include bare steel pipe, ineffective pipe coating, or ineffective cathodic protection.
- Waivers should not be considered for pipeline segments where identified threats (such as selective seam corrosion) include issues where time-to-failure calculations are unreliable.
- Waivers should be revoked if failures occur from causes within operators' primary responsibility (corrosion, material failures, incorrect operation, etc.).
- Waiver applications, supplemental information, correspondence, and final waivers should all be included in an easy-to-locate, publicly-accessible, Web-based docket.
- All National Environmental Policy Act requirements must be fulfilled in development of PHMSA's waiver process.

We also would like to point out that while the trend for the number of significant pipeline incidents in the past 10 years for onshore liquid pipelines is declining, the trend for significant incidents for onshore natural gas transmission pipelines is increasing. The following graphs illustrate these trends.


Significant Onshore Gas Transmission Pipeline Incidents 1997-2007
Source: PHMSA Significant Incidents Files as of Feb. 19, 2008
70
65
60
55
50
45
40
35
30
25
20
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007


Significant Onshore Liquid Transmission Pipeline Incidents 1997-2007
Source: PHMSA Significant Incidents Files as of Feb. 19, 2008
160
150
140
130
120
110
100
90
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007

Liquid pipelines, with nearly 130,000 fewer miles nationwide than gas pipelines, have nearly twice as many significant incidents but their incident trend is downward. The apparent increase in the number of significant incidents for natural gas transmission pipelines is notable because it illustrates that there are still significant safety problems to address with respect to natural gas transmission pipelines.

The discussion today has been on possibly increasing the reassessment interval for gas pipelines, but we shouldn't lose sight of the fact that the integrity management rules that require any such assessment only apply to pipelines within "high consequence areas." According to PHMSA, less than 10% of natural gas transmission pipeline mileage is within those high consequence areas, so people living, working, traveling, or recreating along the other 90%+ of this Nation's natural gas pipelines are not guaranteed the same protections. Mr. Corbin Fawcett who I mentioned earlier as being killed while driving along an interstate highway in Louisiana was one of those people outside of a high consequence area who paid the ultimate price for not being in an area with these added protections.

We would like Congress and PHMSA to consider a phased expansion of the pipeline mileage to be included within the definition of High Consequence Areas (HCA). This definition, to a large extent, is what determines which transmission pipeline segments are required to be inspected under the integrity management rules. At this time, HCAs mainly include populated areas, areas where people congregate, and for liquid pipelines drinking water sources and certain biologically significant areas, plus navigable waterways. This was a good starting place for integrity management since it represented the most crucial areas and a significant undertaking for the industry.

As the first phase of the baseline integrity management testing is now nearing completion we believe operator and regulator experience, along with the increases in industry infrastructure needed to undertake these inspections, makes it possible to expand the definition of HCA to include important areas that were left out of the initial definition. These left-out areas would include things like important historical sites, national parks and wildlife refuges, heavily traveled highways, and in the case of liquid pipelines swimable and fishable waters. While we are not opposed to the pipeline industry saving time and money through the waiver process being discussed here today, we think some of that time and money should be reinvested to ensure that more people like Corbin Fawcett don't lose their lives because they happened to be on the wrong side of some risk assessment line.

PIPELINE SAFETY INFORMATION GRANTS

The Pipeline Safety Trust has long pushed for technical assistance grants to allow local communities that are most at risk from the potential hazards of pipelines in their midst to take a more active and informed role in determining those risks, and to allow the public to play a meaningful part in the various processes that lead to pipeline safety standards and regulations. These grants will promote better technical and policy decisions, and will increase communication between diverse members of the public, governmental decisionmakers, and members of the pipeline industry. The grants will allow members of the public to hire independent experts to explain, analyze, and interpret technical data.

This committee, led by now-Chairman Boucher, established the Pipeline Safety Information Grants program in the Pipeline Safety Improvement Act of 2002. The committee reaffirmed its support for this program in PIPES, pushing for the implementation of the technical assistance grant program even harder by requiring PHMSA to set up a competitive process for these grants before PHMSA would be allowed to award any grants under section 60114 for Technology Development Grants for damage prevention.

It has been over 5 years since Congress called for these community grants, but to our knowledge PHMSA has yet to set up a competitive process, and certainly none of these grants have been awarded. During that period, the "local communities and groups of individuals" as defined in the USC 60130 who are in need of technical assistance for "engineering or other scientific analysis of pipeline safety issues" or for "promotion of public participation in official proceedings" have been left to their own devices in the face of processes and proceedings that are overwhelmingly steered by the pipeline industry and its comparatively limitless dollars.

One of the Pipeline Safety Trust's core beliefs is that pipeline safety is a three-legged stool: one leg represents pipeline regulators, one leg represents the pipeline industry, and the last leg represents the local communities that are positively and negatively affected by pipelines. Take away any one leg and the stool becomes dangerously unstable. Local governments and community organizations generally do not have the resources to be a meaningful leg in this stool, which is why these grants are so important for pipeline safety.

Here are some specific examples of how these grants could provide real value for pipeline safety:

- PHMSA is currently undertaking a very valuable effort called the Pipelines and Informed Planning Alliance (PIPA). This effort in part is a result of a provision in the Pipeline Safety Improvement Act of 2002, which required PHMSA to study the concerns with population encroachment along transmission pipeline rights-of-way. The PIPA process has brought together all the stakeholders to develop solutions to the thorny issues involving pipelines intersecting with proposed local developments. One significant barrier to the success of this initiative is the lack of participation by local governments and citizens who actually understand and control the local zoning, permitting, and planning processes; a key impediment to their participation is the cost of participation in terms of travel, costly conference calls, and lack of staffing. Providing a technical assistance grant to a group that could ensure basic staff support and cover participation costs by local governments and citizen participants would remove this impediment.
- The Pipeline Safety Trust received numerous calls in the past year from members of local school boards who are looking at locating new schools on property that contains, or is near, a pipeline. Pipeline Safety Information Grants could enable a school board to hire an independent consultant to research the existing information about pipeline risk, and then help educate and inform the school board about the particular risks of their proposed site and ways to mitigate those risks. That information could then be shared with other school districts faced with similar decisions.
- For the past few years, local governments and citizens across the country have been faced with numerous new pipeline proposals. They have serious questions about how pipelines are installed, maintained, and inspected, as well as how possible incidents could affect their safety, drinking water sources, and properties. These grants could provide such communities a source for independent technical information that could help them focus their concerns on the proper threats, and thus become valuable partners in safely siting needed new pipelines. The information that comes out of these grants could then be shared with other local governments.
- The Washington City and County Pipeline Safety Consortium and the Kentucky Pipeline Safety Advisory Committee were formed after major pipeline failures and involved a broad spectrum of stakeholders looking for solutions to keep their states safe and avoid further pipeline accidents. Technical assistance grants under Sec. 60130 could help fund staff time for these outstanding examples of independent pipeline safety initiatives and pipeline safety involvement by multiple stakeholders. Such local involvement is critical as PHMSA moves forward in the areas of pipeline damage prevention and encroachment.
- Finally, another potentially important use of these grants is to pay for increased public involvement in industry standards development and to assist in public comments on technical regulations and the various waiver processes. For example, in the Midwest a waiver was granted by PHMSA for a very large yet-to-be-built gas pipeline to operate at higher pressure with thinner steel before local governments or affected communities even knew such a pipeline was proposed.

Ultimately, implementation of the Pipeline Safety Information Grants program will not only help local communities, but it will also help pipeline operators and PHMSA by ensuring that communities are able to educate themselves and receive independent information that builds confidence in the safety of a particular pipeline or proposed activity by pipeline operators.

LOW STRESS PIPELINES

The 200,000 gallon BP crude oil pipeline leak on the North Slope of Alaska found during the winter of 2006, the additional leak found in the summer of 2006 followed by a partial shut-down of the Prudhoe Bay Oil Field, and the ensuing fiasco concerning BP's previously inadequate low-stress pipeline maintenance and testing have made it clear that all low-stress oil pipelines should fall under the same minimum federal standards as other transmission pipelines. Likewise, those sections of pipeline, which could affect Unusually Sensitive Areas should be required to meet the same integrity management provisions as higher-stress transmission pipelines.

Section 4 of PIPES remedied the unwarranted low-stress pipeline exemption and required PHMSA to "issue regulations subjecting low-stress hazardous liquid pipelines to the same standards and regulations as other hazardous liquid pipelines" (emphasis added) with limited exceptions for pipelines regulated by the U.S. Coast Guard and certain short-length pipelines serving refining, manufacturing, or truck, rail, or vessel terminal facilities. Section 4 of PIPES clear directive to PHMSA has been only partially followed, and PHMSA has missed the mandated December 31, 2007 requirement for issuance of regulations.

Since passage of PIPES, PHMSA issued a proposed rule on May 18, 2007 covering "Protecting Unusually Sensitive Areas from Rural Low-Stress Hazardous Liquid Pipelines." Though several members on the Technical Hazardous Liquid Pipeline Safety Standards Committee objected, PHMSA decided to pursue a two-phase approach to meet the Section 4 mandate, with Phase One covering rural low-stress pipelines affecting Unusually Sensitive Areas and Phase Two covering all other rural low-stress pipelines. The Trust and others commented on several inadequate provisions of the Phase One proposed rule which, contrary to Section 4, does not apply "the same standards and regulations" to low-stress hazardous liquid pipelines that higher-stress pipelines must meet. In contrast to higher-stress pipelines, the proposed rule contains a uniform distance approach to determining those pipelines that "could affect" an Unusually Sensitive Area (ironically, the same type of one-size-fits-all approach that industry objects to for the natural gas transmission pipeline reassessment interval). PHMSA's approach is both non-scientific and different from the requirements applying to higher-stress pipelines, thus making it contrary to the requirements of PIPES. As for Phase Two, PHMSA is pursuing data collection prior to rulemaking, and we do not know when that rule—which Congress required to be completed by the end of last year—even will be proposed.

Distribution Integrity Management Program Rulemaking Deadline

Congress also gave PHMSA a deadline of December 31, 2007 in PIPES to prescribe minimum standards for integrity management of natural gas distribution pipelines. While it is clear that PHMSA has been working on integrity management standards for distribution pipelines, it is also clear that they have missed this deadline.

One of our particular interests with distribution pipelines is the use of Excess Flow Valves (EFVs). PIPES requires the use of EFVs for most new and replaced service lines in single family residential housing after June 1, 2008. We hope that PHMSA makes every effort to meet this important deadline. The National Transportation Safety Board (NTSB) has studied and recommended the use of EFVs for years, firefighters nationwide promote their use, there are millions of EFVs in successful use nationwide, and Congress has mandated their use. We hope that Congress will keep a close eye on this upcoming deadline to make sure we have finally moved past the study-it-to-death stalling tactics from past years so there are no further delays in the nationwide use of these important safety devices.

Enforcement Transparency and Other Forms of Public Information

In our opinion, one of the true successes of PIPES has been the rapid implementation by PHMSA of the enforcement transparency section of the act. It is now possible for affected communities to log onto the PHMSA website *(http://primis.phmsa.dot.gov/comm/reports/enforce/Enforcement.html)* and review enforcement actions regarding pipelines in those communities. This transparency should increase the public's trust that our system of enforcement of pipeline safety regulations is working adequately or will provide the information necessary for the public to push for improvements in that system.

Transparency in enforcement documentation represents just one of the relatively new efforts by PHMSA to provide valuable information for public review. PHMSA's Stakeholder Communications website represents a huge improvement in transparency in the last few years, and we also appreciate PHMSA's efforts in getting the National Pipeline Mapping System available again to the public.

The one area where PHMSA could go even further in transparency would be in establishing a web-based system that would allow public access to basic inspection information about specific pipelines. An inspection transparency system would allow the affected public to review when PHMSA and its state partners inspected particular pipelines, what was found, and how any concerns were rectified. Inspection transparency should increase the public's trust in the checks and balances in place to make pipelines safe.

State Damage Prevention Programs

We strongly support the section in PIPES that encourages states to increase their efforts surrounding damage prevention. Outside force damage remains one of the top causes of significant pipeline incidents, and is also one of the hardest causes to address by regulation. There is strong evidence of success with state damage prevention programs that include elements of stakeholder education, collaboration, and participation, as well as the use of dispute resolution, enforcement of damage prevention laws, best technologies, and constant evaluation and improvement.

PHMSA appears to be emphasizing these elements in its current communications and programs, but we hope that Congress will keep a close eye on whether PHMSA is providing clear guidance to states in these areas, as well as whether the increased funding included in PIPES actually flows to the states. Without increased funding, it is unlikely that many states will have the ability to increase the effectiveness of their damage prevention programs. The authorization and appropriation of increased funds for these efforts are the responsibility of Congress.

PUBLIC EDUCATION AND AWARENESS FOR THE NEW 811 ONE CALL NUMBER

We are happy to see the implementation of the new nationwide 811 One Call number, which will make it easier for people across the country to know where to call before they undertake activities that could cause harm to pipelines. Former Chairman Barton, former Congressman Chris Johns and other members of this Committee deserve all our thanks for their successful effort to include language in 2002 Act that made 811 a reality. While getting the number functioning was a huge undertaking, an even bigger task is to make sure that homeowners, excavators, utility workers, and many others know about and use the 811 number. We hope that Congress will continue to support the 811 effort through ongoing appropriation of funds. The Common Ground Alliance has done a good job of kicking off this effort and using federal funding to leverage private investments, but there is still much work to do.

LEAK DETECTION TECHNOLOGY STUDY

Following a number of high profile liquid pipeline failures where leak detection systems were unable to identify ruptures or ongoing small leaks (including the 200,000 gallon BP North Slope pipeline failure in winter of 2006), PIPES required PHMSA to produce a report by December 31, 2007 to report on these inadequacies and ways to improve leak detection technologies. PHMSA has missed the deadline for this much-needed leak detection technologies report.

INTERNAL CORROSION CONTROL

Following a number of leaks on pipelines on the North Slope in Alaska, PIPES required PHMSA to review whether current regulations regarding internal corrosion on liquid pipelines were adequate, and to produce a report by December 31, 2007 based on this review followed by regulatory implementation. PHMSA has met once with the Technical Hazardous Liquid Pipeline Safety Standards Committee to discuss internal corrosion issues, but to date PHMSA has not issued a report on the review or started any rulemaking activities. PHMSA has missed the deadline for this much-needed internal corrosion control report and its follow-up activities. Additionally, states and federal entities such as the Minerals Management Service (MMS) and the U.S. Coast Guard that are updating their pipeline regulations now are missing opportunities to include PHMSA's latest internal corrosion control findings in their respective regulatory updates. MMS, in fact, recently closed its public comment period for a comprehensive overhaul of its pipeline safety regulations.

THE NEED TO ADDRESS UNREGULATED PIPELINES

Pipelines that are not regulated by PHMSA, like rural low-stress hazardous liquid pipelines prior to PIPES' mandate, can have releases with serious consequences that are not even reported to PHMSA nor, in many instances, to any government entity (depending on state or offshore reporting requirements). 49 CFR 195.1(b), for instance, contains nine exemptions to PHMSA's regulatory framework for hazardous liquid pipelines, including the rural low-stress pipeline exemption that has not yet been removed. As a result, unregulated pipelines—whether by statute or by regulation—only become regulated after significant safety or environmental tragedies occur.

To prevent such tragedies, Congress should require the NTSB to study the likelihood of releases from currently unregulated pipelines using available release data from the National Response Center, state release reporting databases, the media, etc. Such a report should include recommendations to Congress to ensure regulatory coverage of all pipelines that might pose significant safety or environmental risks. The report should examine such things as whether the current definition of gathering lines inhibits regulatory coverage of such pipelines, and whether produced water lines should have safety requirements under PHMSA just as offshore produced water lines do under MMS regulations.

Finally, the Trust encourages the Committee to determine why the NTSB has not investigated many recent, significant pipeline accidents such as BP's North Slope pipeline incidents in 2006. Such investigations and NTSB's subsequent recommendations provide critical information for Congress, PHMSA, the pipeline industry, and the public to examine during future reauthorization efforts.

We should all celebrate the progress that has been made since the passage of the Pipeline Safety Improvement Act of 2002 and PIPES, while acknowledging that continuous evaluation and improvement can make pipelines considerably safer yet, and can enhance the public's trust in pipelines.

Thank you again for this opportunity to testify today. The Pipeline Safety Trust hopes that you will closely consider the ideas and analysis we have brought forward. If you have any questions now or at anytime in the future, the Trust would be glad to answer them.

Summary of Testimony

Regarding the reassessment interval for gas transmission pipelines, we find that PHMSA's proposed waiver process is technically sound. Congress should consider implementing fees for waiver applications to provide PHMSA with the resources to get the job done. We believe it is important to maintain the Congressionally mandated reassessment interval. The trend for significant incidents for onshore natural gas transmission pipelines is increasing, so as the initial baseline assessment is completed it is time to expand the definition of high consequence areas to further reduce incidents.

Regarding Community Technical Assistance Grants, after more than 5 years PHMSA has yet to set up a competitive process, and none of these grants have been awarded. Congress must ensure that the program is established and funded fully.

Regarding low stress pipelines, section 4 of PIPES clear directive to PHMSA has only been partially followed, and PHMSA has missed the mandated December 31, 2007 requirement for issuance of regulations.

Regarding integrity management for gas distribution pipelines, while it is clear that PHMSA has been working on integrity management standards for distribution pipelines, it is also clear that they have missed the deadline set out in PIPES.

One of the true successes of PIPES has been the rapid implementation by PHMSA of the enforcement transparency section of the act. PHMSA's Stakeholder Communications website represents a huge improvement in transparency in the last few years, and we also appreciate PHMSA's efforts in getting the National Pipeline Mapping System available again to the public. The one area where PHMSA could go even further in transparency would be a Web-based system that would allow public access to basic inspection information about specific pipelines

PIPES held a promise of increased funding to states that implement sound damage prevention programs. Congress should keep a close eye on whether PHMSA is providing clear guidance to states in these areas, as well as whether the increased funding included in PIPES actually flows to the states. Congress should ensure that the money is not only authorized, but also appropriated.

PHMSA has missed the deadline for the much-needed leak detection technologies report, as well as the deadline for this much-needed internal corrosion control report and its follow-up activities.

Mr. Wynn. Thank you for your testimony. I am going to try to pronounce this correctly, Mr. Preketes. Preketes, I was way off, I apologize.

STATEMENT OF PAUL PREKETES, SENIOR VICE PRESIDENT OF ENERGY, DELIVERY CONSUMERS ENERGY

Mr. Preketes. Good afternoon, Chairman and members of the committee. I am pleased to appear before you today and wish to thank the committee for calling this hearing. My name is Paul Preketes, Senior Vice President of Energy Delivery for Consumers Energy in Michigan. I am here testifying today on behalf of the American Gas Association and the American Public Gas Association. AGA represents over 200 local distribution companies that deliver natural gas to more than 64 million homes, businesses, and industries throughout the United States and the APGA is a national association of public gas systems that encompass over 950 communities.

Local distribution companies, or LDCs, are the face of the industry. Consequently we take very seriously the responsibility of continuing to deliver natural gas to our communities safely, reliably, and affordably. Safety is our business. Natural gas utilities spend an estimated $6.4 billion each year in safety and related activities. The Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 or the PIPES Act, contained several substantive provisions that focused on LDC-related issues.

Because excavation damage prevention is the leading cause of natural gas distribution pipeline incidents, the most important of these was the section excavation damage prevention. In writing the law this committee created an incentive for states to adopt stronger damage prevention programs. This was a major step toward expanding the safety culture beyond just our industry and creating a situation where all stakeholders can come together to focus on this issue. We commend the Energy and Commerce Committee for the attention that was given to improving state excavation damage prevention and for having made the nine elements the centerpiece of a 2006 bill.

I am happy to report that in 2007, key national stakeholders formed the Excavation Damage Prevention Initiative, EDPI, to build upon the good work done by this committee. The EDPI produced a document entitled, “A Guide to the Nine Elements” to provide guidance to states working to incorporate the nine elements into their existing pipeline safety programs. Last month the AGA partnered with the National Association of Regulatory Utility Commissioners to continue work on this issue. With AGA’s support NARU passed a resolution urging state commissions to review their current excavation damage prevention programs and to consider the EDPI’s “Guide to the Nine Elements” document in making revisions and improvements in order to incorporate fully the elements of the PIPES Act.

Another example of progress with the damage prevention, as Mr. Kessler said, was the Common Ground Alliance’s successful roll-out of 811, the National Call Before You Dig number, that was kicked off and went live in May of 2007. The other significant section of the bill that related to natural gas utilities was a section on Distribution Integrity Management Programs or DIMP. For 2 years, PHMSA has been diligently working with key stakeholders to develop a DIMP regulation. We are very supportive of this effort and are strong advocates of Integrity Management. We fully support taking the responsible course of action in seeking to enhance distribution pipeline integrity and we are confident that PHMSA’s work today will result in a DIMP rule that enhances safety while providing flexibility.

The diversity among gas distribution pipelines makes it impractical to establish prescriptive requirements that would be suitable for all circumstances. In order to achieve maximum distribution safety enhancements, a high level rule that contains an appropriate level of flexibility, including a strong risk assessment component and which takes into account all the various stakeholder concerns, is essential. One size fits all is not an appropriate solution for distribution integrity. This will allow each natural gas facility operator to manage their system and ensure a goal of actually improving system safety based on individual companys' system performance characteristics and not simply following prescriptive rules that in many cases do not enhance the safety of particular systems. It would be most appropriate to require that all distribution pipeline operators, regardless of size, implement a risk-based integrity management program that would contain seven key risk assessment elements.

The PIPES Act also contains the provision requiring the insulation of excess flow valves on new or fully replaced services on single family dwellings. EFVs can effectively stop the flow of gas in situations where there is a rapid release of gas. It should be noted, however, that the excess flow valves are not effective in stopping the release of gas in small leaks. While EFVs are a helpful safety device, they are only one component of pipeline safety. The industry has made significant progress in installing these devices. In 2006, the AGA completed a study of its members when Pipeline Safety Legislation was being reauthorized. At that time, about 66 percent of the new services installed by its members included excess flow valves, and my company Consumers Energy was among them.

With respect to control room management, AGA, APGA believe that the vast majority of operators have already implemented effective procedures for control room operations. This is in part confirmed by the fact that there are no reportable natural gas incidents from the past 10 years in which a primary cause was the action of the gas controller. In fact, our associations are not aware of any natural gas incidents attributed to a natural gas controller's actions.

With respect to the 7 year inspection interval for transmission integrity, AGA supports the testimony of Interstate National Gas Association and the effort to establish technically-based reassessment in rules similar to AS&E B31.8S consensus standard in lieu of the existing 7 year intervals. I appreciate the opportunity to testify today and would be happy to answer any questions.

[The prepared statement of Mr. Preketes follows:]

Statement of Paul Preketes

Good morning, Mr. Chairman and members of the Committee. I am pleased to appear before you today and wish to thank the Committee for calling this hearing. Pipeline safety is a critically important issue, and I commend you for not only holding this hearing, but for all the work that you and your colleagues have done over the years to ensure that America has the safest, most reliable pipeline system in the world. My name is Paul Preketes. I am the senior vice president of energy delivery of Consumers Energy, based in Michigan. Consumers Energy provides natural gas service for heating and other uses to nearly 1.7 million customers in 54 of the 68 counties in Michigan's Lower Peninsula. It serves an area that spans 13,000 square miles and includes 215 cities and villages. Among the largest areas served are Bay City, Flint, Jackson, Kalamazoo, Lansing, Macomb, Midland, Royal Oak, Saginaw, and Livonia. More than one-half of the utility's gas customers are in metro Detroit.

I am here testifying today on behalf of the American Gas Association (AGA) and the American Public Gas Association (APGA). AGA, founded in 1918, represents 200 local distribution companies that deliver natural gas to more than 64 million homes, businesses and industries throughout the United States. A total of 69 million residential, commercial, and industrial customers receive natural gas in the U.S., and AGA's members deliver 92 percent of all the natural gas provided by the Nation's natural gas utilities. AGA is an advocate for local natural gas utility companies and provides a broad range of programs and services for member natural gas pipelines, marketers, gatherers, international gas companies and industry associates.

APGA is the national association of publicly-owned natural gas distribution systems. There are currently approximately 950 public gas systems in the United States. Publicly-owned gas systems are not-for-profit, retail distribution entities that are owned by, and accountable to, the citizens they serve. They include municipal gas distribution systems, public utility districts, county districts, and other public agencies that have natural gas distribution facilities.

The gas utility's distribution pipes are the last critical link in the natural gas delivery chain. Local distribution companies, or LDC's, are the "face of the industry." Our customers see our name on their bills, our trucks in the streets, and our company sponsorship of many civic initiatives. We live in the communities we serve and interact daily with our customers and with the state regulators who oversee pipeline safety. Consequently, we take very seriously the responsibility of continuing to deliver natural gas to our communities safely, reliably, and affordably.

Indeed, SAFETY is our business. It has to be, because the environment in which we work has several factors over which we have no direct control—such as the public, excavators, weather, floods, and earth movement. However, LDCs contend with these every day. Therefore as an industry, we make safety our number one priority—subscribing to the philosophy that safety is our number one priority, for our employees, our customer and the public. It all begins with the Tone at the Top and building a strong culture around safety. Natural gas utilities spend an estimated $6.4 billion each year in safety-related activities. Approximately half of this money is spent in compliance with federal and state regulations. The other half is spent as part of our companies' programs and activities that go beyond mere compliance, to ensure that our systems are safe and that the communities we serve are protected.

EXCAVATION DAMAGE PREVENTION

The Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (PIPES Act) contained several substantive provisions that focused on LDC related issues. The most important of these is the section on Excavation Damage Prevention. Excavation damage is the leading cause of natural gas distribution pipeline incidents. The latest statistics from DOT show that in 2007, over forty percent of incidents on distribution pipelines were from third party excavation or outside forces like automobiles hitting gas meters. If you exclude incidents classified as "Miscellaneous" or "Other," this statistic increases to almost eighty percent.

In writing the law, this committee created an incentive for states to adopt stronger damage prevention programs. This was a major step towards expanding the safety culture beyond just our industry—and creating a situation where all the stakeholders can come together to focus on this issue. For over 3 years, a group of excavation damage prevention stakeholders (composed of excavators, underground facility owners, natural gas facility operators, safety advocates, state regulators, and the public) worked together to craft the nine "Elements" that were eventually contained in the PIPES Act of 2006. We commend the Energy and Commerce Committee for the attention that was given to improving state excavation damage prevention, and for having made the nine elements a centerpiece of the bill. We are now focused on building upon that earlier national stakeholder collaboration. I am happy to report that, in 2007, key national stakeholders formed the Excavation Damage Prevention Initiative (EDPI) to build upon the good work done by this committee. The EDPI produced a document entitled "A Guide to the 9 Elements" to provide guidance to states working to incorporate the "9 Elements" into their existing pipeline safety programs.

Last month AGA partnered with the National Association of Regulatory Utility Commissioners (NARUC), during its February 2008 Winter Meetings in Washington, D.C., to continue work on this issue. With AGA's support, NARUC passed a resolution urging state commissions to review their current excavation damage prevention programs and to consider the EDPI's "Guide to the 9 Elements" document in making revisions and improvements in order to incorporate fully the nine Elements of the PIPES Act. There is still much work to be done. Each state is unique and the local stakeholders have to decide how best to implement the nine elements. Sometimes enforcement resides with the state attorney general, while in other states the utility commission can enforce damage prevention rules. With the

EDPI guidance document, the support of PHMSA, and the national trade associations, we believe local stakeholders can make the legislative and regulatory changes needed to enhance damage prevention programs in their particular states.

Another example of progress with damage prevention was the Common Ground Alliance's successful roll-out of 811, the national "Call Before You Dig" number that was kicked off in May 2007. The Common Ground Alliance (CGA) is an association dedicated to ensuring public safety, environmental protection, and the integrity of underground services by promoting effective damage prevention practices. Its members focus on reducing damages to all underground facilities in North America through shared responsibility among all stakeholders. Members include pipeline operators, excavators, locators, road builders, public works, state One Call organizations, federal and state regulators, and many others. The CGA has grown to over 1,300 individual members, 165 member organizations, and 40 sponsors. The initial 811 roll-out effort included 179 broadcasts in 73 media markets. The coverage reached 75 million Americans. Stakeholders are now incorporating the "Call 811" message in their advertising material. I have had the privilege or representing the natural gas industry and serving as the CGA board chair.

Distribution Integrity Management

The other significant section of the bill that related to natural gas utilities was the section on Distribution Integrity Management Programs (DIMP). For 2 years, PHMSA has been diligently working with key stakeholders to develop a DIMP regulation. We are very supportive of this effort, and are strong advocates of integrity management. We fully support taking a responsible course of action in seeking to enhance distribution pipeline integrity, and we are confident that PHMSA's work to date will result in a DIMP rule that enhances safety while providing flexibility. The collaboration between PHMSA, state regulators, utility system operators, fire marshals, and the public has been exceptional. PHMSA should be commended for leading such an effort. It should be noted that distribution integrity management impacts a large portion of America's energy infrastructure. The diversity among gas distribution pipelines makes it impractical to establish prescriptive requirements that would be suitable for all circumstances.

In order to achieve maximum distribution safety enhancements, a high-level rule that contains an appropriate level of flexibility including a strong risk assessment component, and which takes into account all the various stakeholder concerns, is essential. This will allow each natural gas facility operator to manage their system and ensure a goal of actually improving system safety based on individual company systems performance characteristics, and not simply following prescriptive rules that, in many cases, do not enhance the safety of particular systems. It would be most appropriate to require that all distribution pipeline operators, regardless of size, implement a risk-based integrity management program that would contain seven key elements:

1. Develop and implement a written integrity management plan.
2. Know the infrastructure performance.
3. Identify threats, both existing and of potential future importance.
4. Assess and prioritize risks.
5. Identify and implement appropriate measures to mitigate risks.
6. Measure performance, monitor results, and evaluate the effectiveness of its programs, making changes where needed.
7. Periodically report performance measures to its regulator.

These seven elements will be clarified by way of guidance being developed by a nationally recognized standards body to provide a basis for operator compliance and for regulator enforcement.

Though PHMSA did not meet the December 2007 deadline for promulgating a final rule, we believe the progress that has been made thus far is significant. Furthermore, given the magnitude of the distribution system (2 million miles), the number of parties involved (including federal regulators, 50 state agencies and over 1200 operators), the time taken to ensure a workable regulation that can be implemented and enforced has been time well spent.

Excess Flow Valves

The PIPES Act also contained a provision requiring the installation of excess flow valves (EFVs) on new or fully replaced service lines on single family residential dwellings. In situations where there is a rapid release of gas, EFVs can effectively stop the flow of gas. It should be noted that excess flow valves are not effective in stopping the release of gas in small leaks. Therefore, while EFVs are a helpful safety device, they are only one component of pipeline safety.

The industry has made progress in installing these devices. In 2006, AGA completed a survey of its members when pipeline safety legislation was being reauthorized. At that time, about 66 percent of the new services installed by its members included excess flow valves. In 2007 AGA sponsored a workshop to explain the benefits and limitations of excess flow valves. In addition, the implementation of EFVs has been discussed within AGA's technical committees. Gas utilities that have voluntarily installed EFVs explained the technical challenges involved with installing EFVs in various situations.

Since the passage of the PIPES Act and the AGA workshop, more operators have voluntarily begun to install EFVs on new service lines where installation is feasible. The rate will be close to 100 percent once the regulatory requirements are finalized. I say close to 100 percent because there are certain facilities with low pressures or significant particles or liquids in the natural gas, excess flow valves should not be installed.

Control Room Management

AGA and APGA believe that the vast majority of operators have already implemented effective procedures for control room operations. This is in part confirmed by the fact that there are no reportable natural gas incidents from the past 10 years in which the primary cause was the action of a gas controller. In fact, our associations are not aware of any natural gas distribution incidents attributable to a natural gas controller's actions. Even with no incidents attributable to the actions of a gas distribution controller, gas utilities support legislative requirements to enhance control room operations.

AGA has a gas control committee that meets regularly to discuss technical issues, develop guidelines, and share best practices. PHMSA's staff has attended the gas control fall and spring meetings of the last few years. This has helped both parties understand the safety and operational issues necessary for new regulations.

There is a vast diversity in the control rooms of gas distribution, gas transmission and hazardous liquid operations. Natural gas has the properties of a compressible fluid that can expand and contract. Gas transmission operations operate at high pressures and have compressor stations about every 150 miles. Distribution pipelines operate at much lower pressures and rarely ever have compressors. Furthermore, the "control rooms" of many small utilities may do little more than indicate the pressure and flowrate, at one or more gate stations, where the utility receives natural gas from its transmission supplier. Hazardous liquid pipelines primarily move incompressible fluids, like crude oil across the country, but are vastly different from gas transmission pipelines.

PHMSA held a workshop on May 23, 2007 in Washington DC to address the control room management issue of all three pipeline sectors. Pipeline controllers from all three pipeline sectors provided technical presentations, along with PHMSA staff. All parties agree that there is vast diversity in the pipeline operations of gas distribution, gas transmission, hazardous liquids, and large and small operators. Because of this diversity, safety processes appropriate for one operator are often not practical for another operator. Furthermore, such diversity makes a uniform national regulation difficult to develop and implement. AGA believes that it is in all stakeholders' best interests for the final regulation to be written at a high level, reasonably providing operators the flexibility to adopt practices and procedures which are appropriate to their own system.

PHMSA has made much progress in developing a proposed rule. PHMSA has presented nine elements to enhance pipeline control room management. We support these enhancements.

1. Clearly define the roles and responsibilities of controllers to ensure their prompt and appropriate response to abnormal operating conditions.
2. Formalize procedures for recording critical information and for exchanging information during shift turnover.
3. Establish shift lengths and schedule rotations to protect against the onset of fatigue; and educate controllers and their supervisors in fatigue mitigation strategies and how non-work activities contribute to fatigue.
4. Periodically review SCADA displays to insure controllers are getting clear and reliable information from field stations and devices.
5. Periodically audit alarm configurations and handling procedures to provide confidence in alarm signals and to ensure controller effectiveness.
6. Involve controllers when planning and implementing changes in operations, and maintain strong communications between controllers and field personnel.

7. Determine how to establish, maintain, and review controller qualifications, abilities and performance metrics, with particular attention to response to abnormal operating conditions.
8. Analyze operating experience including accidents and incidents for possible involvement of the SCADA system, controller performance, and fatigue.
9. Validate the adequacy of controller-related procedures, training and the qualifications of controllers, possibly annually through involvement by senior level executives of pipeline companies.

Let me summarize my comments on pipeline controllers by saying that all pipeline controllers fall under the provisions of the operator qualification (OQ) regulations. Therefore, these individuals are already trained and qualified in accordance with these regulations and company OQ programs. Controllers must be proficient in communication protocols, in recognizing abnormal operating conditions, and in emergency response protocols. Training is extensive and pipeline companies have elements in their training plans, such as training on the fundamental characteristics of natural gas, understanding of the individual pipeline system, supervised operation of the pipeline system, and written exams. All of these steps must be completed and proficiency demonstrated before an individual receives management approval to operate the system without direct oversight of a more experienced and qualified controller.

Transmission Integrity Management

The regulation for transmission integrity management was finalized in December 2003. The Associations believe the program has been very successful in enhancing safety. Operators are ahead of schedule in accessing transmission pipelines. More than 50 percent of the total pipeline miles in high consequence areas have been inspected under the integrity management regulation, well before the December 2007 deadline. Industry, regulators, and technical consultants have worked to develop and implement new technologies that can assess transmission pipelines in situations where internal inspection devices or pressure testing are not feasible. These indirect assessment methods, like External Corrosion Direct Assessment, have been very beneficial to gas utilities that operate transmission pipelines.

Operators have learned much during the implementation of the regulation and AGA believes there can be some improvements in the current regulation. AGA supports the testimony of the Interstate Natural Gas Association of America and the effort to establish technically based re-assessment intervals similar to the ASME B31.8s consensus standard in lieu of the existing seven-year intervals.

Summary

The natural gas utility industry is proud of its safety record. We are committed to continuing our efforts to operate safe and reliable systems and to strengthen excavation damage prevention laws in every state.

Representatives from the public, state and federal government, industry, and other stakeholders have reached consensus on a framework for Distribution Integrity Management. The seven basic elements necessary for an effective program can be incorporated into a risk-based, performance-oriented federal regulation. The installation of excess flow valves will be part of DIMP. Even before the mandated effective date, there has been an increase in the number of new or replaced service lines being installed with this safety device.

Mr. WYNN. Thank you. We will now hear from Mr. Felt.

STATEMENT OF TIMOTHY FELT, PRESIDENT AND CEO, EXPLORER PIPELINE, CHAIRMAN, ASSOCIATION OF OIL PIPELINES

Mr. FELT. Thank you, sir, that is the correct pronunciation of my name.

Mr. WYNN. All right.

Mr. FELT. Members of the subcommittee, my name is Tim Felt. I am President and CEO of Explorer Pipeline, headquartered in Tulsa, Oklahoma. I am Chairman of the Association of Oil Pipelines and Power Leadership of the Pipeline Segment of the API. I appreciate the opportunity to appear to today on behalf of AOP and

API. Together these organizations represent the vast majority of U.S. oil pipeline transportation companies. It has been just over a year since the enactment of the Pipeline Inspection, Protection, Enforcement, and Security Act of 2006. On behalf of our members I wish to thank you for your leadership in passing that comprehensive and very important legislation.

As a subcommittee reviews the current state of pipeline safety and the progress that has been made since the PIPES Act, there are a few main points that I would like to emphasize. First, industry and DOT have cooperated to achieve continued improvement in pipeline safety. And this improvement is demonstrated by our industry's record. This record is reflected on the charts that accompany my testimony. In 2 weeks the oil pipeline industry will be in compliance with the deadline for the 7 year baseline assessment of the Integrity Management Plan. We are proud of the demonstrated improvement in safety from this program and look forward to continual improvement. The cornerstone of the PIPES Act was a focus on underground damage prevention. The oil pipeline industry is working aggressively with other industry and government stakeholders to encourage and assist the states implementation of the nine elements to effective damage prevention. We believe the implementation of the other requirements in the PIPES Act will continue to effectively improve pipeline safety and reliability.

About 40 percent of the total U.S. energy supplied comes from petroleum but the transportation sector depends on petroleum for 96 percent of its energy. Two-thirds of domestic crude oil or refined products transportation is provided by pipeline. Pipelines do this safely and efficiently, and the cost to transport a gallon of petroleum by pipeline is very low, typically two to four cents per gallon. Oil pipelines are common carriers whose rates are controlled by a Federal Energy Regulatory Commission. Oil pipeline income is driven only by the volume transported and does not depend on the price of products transport; in fact, high oil and refined product prices have a negative impact on oil pipeline income by raising power costs and reducing demand for petroleum.

Oil pipeline operators have been subject to the DOT's Pipeline Integrity Management Regulations since March 2001. DOT's inspections of operators' plans shows that integrity testing will eventually cover approximately 82 percent of the Nation's oil pipeline infrastructure almost four times the original estimate.

In the next 2 weeks large oil pipeline operators will be in compliance with the required baseline testing deadline of the highest risk segments set by the regulations. DOT has audited each of these operators under these regulations at least two times. An initial quick hit audit and a subsequent full audit. Although operating under a different deadline the same program has been followed for the smaller operators.

Operators are repairing conditions in need of repair and less serious conditions that are found in the course of investigating certain conditions. There have been over 3,800 conditions repaired or mitigated that needed immediate attention. Over 14,000 other conditions, repaired on a scheduled basis and an additional 32,000 features repaired that were not required by the program. Operators are fixing what they find often going beyond the requirement of the law.

As a result of this program the oil pipeline spill record has improved dramatically in the last 8 years, as the exhibits show. The first chart shows a decline of over 40 percent in both the number of spills and the volume released from pipeline facilities. When measured just along the right of way the area with the most direct potential to affect the public and the environment both the number and volume of spills have declined over 50 percent. For each cause category the trend is down.

As you see in the second chart the most dramatic area of improvement has been in the decline and corrosion related spills nearly 70 percent reduction in less than 8 years. The Integrity Management Program is clearly a major success. We believe full implementation of the PIPES Act will make this good program better. While the number of spills caused by third party damage has declined significantly, these incidents remain of critical concern to our industry because they result in the disproportionate share of the consequences. Damage to buried pipelines during excavation is a persistent preventable and significant cause of pipeline releases. Damage prevention programs are almost totally controlled by the laws of the states and the effectiveness of the framework and enforcement of damage prevention laws varies among the states.

As a board member and chairman of the Common Ground Alliance, an organization that Congress helped start to bring the key interests and damage prevention together in the cooperative effort to improve safety, I can affirm the importance of federal leadership in this area. The PIPES Act provided clear guidance for an effective state program in the nine elements to effective damage prevention.

From the industry prospective we have also stepped up our efforts working with other stakeholders to approach the various states on legislative and/or regulatory improvements. We have committed both financial and staff resources at the company association level to work for improvements in these state programs and are encouraged with the results.

Let me wrap up real quick and say that while biofuels is not the subject of this hearing, I would like to take the opportunity to update the committee on the status of oil pipeline industry's efforts in this area. Last year the industry engaged in an accelerated R&D effort to understand and find solutions to problems of stress corrosion cracking identified with the presence of ethanol in some pipelines and tank facilities. Members of the——

Mr. WYNN. Mr. Felt, I am going to have to ask you to wrap up, we are going to try to get questions in before this vote.

Mr. FELT. OK. Thank you very much.

[The prepared statement of Mr. Felt follows:]

STATEMENT OF TIM FELT

INTRODUCTION

I am Tim Felt, President and CEO of Explorer Pipeline and Chairman of the Association of Oil Pipe Lines (AOPL). I appreciate this opportunity to appear before the subcommittee today on behalf of AOPL and API.

AOPL is an unincorporated trade association representing 48 interstate common carrier oil pipeline companies. The membership is predominately domestic, but also includes companies affiliated with Canadian pipelines. AOPL members transport nearly 85% of the crude oil and refined petroleum products moved by pipeline in the United States. API represents over 400 companies involved in all aspects of the oil and natural gas industry, including exploration, production, transportation, refining, and marketing. Together, these two organizations represent the vast majority of the U.S. pipeline transporters of petroleum products.

Explorer Pipeline operates a 1,880-mile pipeline system that transports gasoline, diesel fuel and jet fuel from the Gulf Coast to the Midwest. Explorer is based in Tulsa, Oklahoma, and serves Houston, Dallas, Fort Worth, St. Louis and Chicago. Through connections with other products pipelines, Explorer serves more than 70 major population centers in 16 states. Explorer currently transports refined products with more than 72 different product specifications for over 60 different shippers. The company does not buy or sell petroleum products; it only provides transportation services. Explorer is owned by subsidiaries of Chevron, Conoco Phillips, Marathon, Sunoco, American Capital, and Shell.

SUMMARY

It has been over just over a year since enactment of the Pipeline Inspection, Protection, Enforcement, and Security Act of 2006 (PIPES Act). On behalf of the members of AOPL and API, I wish to thank the Members of this subcommittee, and the full committee, for their leadership in passing that important legislation. As the subcommittee reviews the current state of pipeline safety and the progress that has been made since the PIPES Act of 2006 became effective, I would like to update the committee on the ongoing safety activities of the oil pipeline industry. First, the oil pipeline industry will complete the 7 year baseline testing for the Integrity Management Program by March 31, 2008. We are proud of the demonstrated improvements in safety this program has produced and look forward to continuing the process used by PHMSA and industry that has brought about this improvement.

THE ROLE OF PIPELINES IN PETROLEUM SUPPLY

About 40 percent of total U.S. energy supply comes from petroleum, 96 percent of the energy used in the transportation sector. Fully two-thirds of the ton-miles of domestic petroleum transportation are by pipeline. The major alternatives to pipelines for delivery of petroleum are tank ship and barge, which require the source and user be located adjacent to navigable waters. Trucks and rail also carry petroleum, but are limited in very practical ways in the volume they can transport. In fact, pipelines are the only reasonable way to supply large quantities of petroleum to most of the Nation's consuming regions. Pipelines do so efficiently, safely and cost-effectively. Liquid pipelines are the backbone of the fuels industry. Pipelines provide a transportation service only. As common carriers, pipeline rates are controlled by the Federal Energy Regulatory Commission. Pipelines have no influence over crude oil or refined product prices nor do they profit from their sale. The continued safe, reliable operation of this critical infrastructure is an appropriate public policy concern and an important joint responsibility of the industry I represent, the Department of Transportation, and the Congress.

PROGRESS REPORT ON PIPELINE SAFETY INTEGRITY MANAGEMENT

Since March 2001 (for large operators) and February 2002 (for small operators), oil pipelines have been subject to a mandatory federal pipeline safety integrity management rule (Title 49, section 195.452) administered by the Pipeline and Hazardous Material Safety Administration (PHMSA). The oil pipeline industry's experience with integrity management preceded the enactment of the Pipeline Safety Improvement Act of 2002. Large operators will complete the required 100 percent of their baseline testing of the highest risk segments by the March 31, 2008 deadline set by the integrity management regulations. PHMSA has inspected the performance of each of these operators under the regulations at least twice—an initial "quick hit" inspection and a subsequent full inspection. Regular inspections are a permanent part of the future.

IMPROVEMENT IN SPILL RECORD

The oil pipeline spill record has improved dramatically in the last 8 years as the attached exhibit shows. The Pipeline Performance Tracking System (PPTS), a voluntary industry program established by AOPL and API, has collected extensive oil pipeline performance data since 1999. The first page of the exhibit shows a decline of over 40% in both the number of spills and the volume released from pipeline facilities. When measured just along the pipeline right-of-way, the area with the most direct potential effect on the public and the environment, both the number and volume of spills have declined over 50%. As you can see in the breakdown on page 2 of the exhibit, the most dramatic area of improvement from the integrity management program has been the decline in corrosion related spills—nearly 70% in less than 8 years. The integrity management program is clearly a major success.

DAMAGE PREVENTION

From the liquid pipeline perspective, the cornerstone of the PIPES Act was the focus on underground damage prevention. While the number of spills caused by third party damage has declined significantly, these incidents remain of critical concern to the industry because they result in a disproportionate share of the consequences. Damage to buried pipelines during excavation is a persistent, preventable, and significant cause of pipeline releases. Releases caused by excavation damage tend to be more dramatic, larger, and more likely to threaten the public and the environment in comparison to releases from other causes. Damage prevention programs are almost totally controlled by the laws of the States. The effectiveness of the framework and enforcement of damage prevention laws varies among the States. The affected interests in damage prevention are typically beyond the reach of any single regulatory authority, so often the most feasible approach is a cooperative one that brings affected interests together in a voluntary commitment to improvement.

As a board member and Chairman of the Common Ground Alliance, an organization that Congress helped start to bring the key interests in damage prevention together in a cooperative effort to improve safety, I can affirm the importance of federal leadership in this area. The PIPES Act provided clear guidance for an effective state program in the "9 elements to effective damage prevention". We hope the additional incentive in the form of financial resources will encourage the states to review their programs—from effectiveness of implementation to enforcement. We are very encouraged that the first round of solicitations is expected to draw a meaningful number of applicants.

From the industry perspective, we have also stepped up our efforts, working with other stakeholders, to approach the various states on legislative and or regulatory improvements. We believe there are some model state programs that accommodate the needs of the broad group of stakeholders—from underground utilities to the construction industries—that could be emulated across a number of states. We have committed both financial and staff resources at the company and association level to work for improvements in these state programs. We are encouraged by the positive response from the states and hope this program will produce real improvements in damage prevention programs including increased state enforcement of laws and regulations. We commend Congress for putting priority attention on this problem and PHMSA for reaching out to the states and to the industry with such commitment to a common purpose.

OIL PIPELINES OPERATED AT LOW STRESS

The PIPES Act required new regulations for oil pipelines operating at low stress. We support PHMSA's approach of implementing the PIPES Act requirement in a two phase approach. We support PHMSA's decision to phase in the rule, addressing first the larger-sized, riskier pipelines and addressing at a later date all other low-stress pipelines except those exempt from PHMSA's oversight as defined in §195.1(b).

We look forward to PHMSA finalizing the regulation for phase-one implementation.

PIPELINE CONTROL ROOM MANAGEMENT

The PIPES Act required the implementation of a plan to address human factors risks associated with control room operations. The liquid pipeline industry has held several workshops with industry controllers, alone and with PHMSA. Our members have a keen interest in the appropriate oversight of control room operations and already have some practices in place that address ergonomics, shift changes and schedules, alertness, appropriate training and qualification, definition of controller roles and responsibilities, and Management of Change. We have been in regular communication with PHMSA concerning an industry consensus standards effort underway to identify issues that operators should take into account when enhancing their plans and procedures. We believe that with the active participation of the senior PHMSA staff, these industry standards will inform as well as form the basis of the control room regulations.

BIOFUELS

While biofuels is not the subject of this hearing, I would like to take this opportunity to update the subcommittee on the status of the oil pipeline industry's efforts in this area. Last year, the industry engaged in an accelerated R&D effort to understand and find solutions to the problem of stress corrosion cracking identified with the presence of ethanol in some pipeline and tank facilities. This research is being carried out under the auspices of the Pipeline Research Council International (PRCI) with the active support and participation of the PHMSA.

Members of the research team believe the test results to date are very encouraging signs that the industry will be able to address the safety and technical challenges to pipeline transportation of ethanol. We will be pleased to provide a more detailed technical briefing for the committee by the research scientists at some future date.

Dating to the early 1990s, operators have found that ethanol has lead to Stress Corrosion Cracking (SCC) in tankage and piping associated with blending, storage and distribution facilities. The safety concerns created by the development of SCC is the focus of the industry's R&D efforts. The test results to date indicate the following:

* The origin and manufacturing process of ethanol has significant impact on development of Stress Corrosion Cracking (SCC);
* The development of SCC is significantly reduced by decreasing oxygen content of fuel grade ethanol, regardless of its origin;
* Potential means to mitigate SCC have been identified and are being tested;
* Early test results indicate a blend of 90% gasoline 10% ethanol may be transported on existing pipelines without causing SCC.

Another technical challenge to pipeline transportation of ethanol is maintaining product quality. Ethanol has an affinity for water which can be picked up as the product flows through the pipeline network. In current multi-product pipelines, small amounts of water enter the pipeline system through fuels as well as terminals and tank roofs. The industry expects that pipeline operators will be able to overcome this issue on an individual pipeline system basis.

We will continue to keep the subcommittee and the rest of Congress informed of developments.

CONCLUSION

We believe the industry efforts in concert with the PHMSA have clearly resulted in significant improvements in the safe operation of hazardous liquid and natural gas pipelines. We are committed to that program with a goal to continuous safety and environmental improvement.

Thank you for the opportunity to testify before the Subcommittee on these important matters.

Mr. WYNN. Thank you and we do have your full testimony and we will certainly take it to heart. We are going to move very briskly and try to conclude the hearing in view of the upcoming vote.

Mr. Mason, if I understood you correctly, you said lower gas usage would impact research and development among other things. Was that—is that— correct?

Mr. MASON. It would lower gas consumption by residential consumers affects the entire rate structure utilities file with that commission. If that included R&D it will affect R&D. If it included capital improvements, it will affect that.

Mr. WYNN. You proposed a decoupling of some sort?

Mr. MASON. Well, what we have talked about at NARUC is a way of reformulating the rates that utilities file at the state level so that they will be held harmless from decreased consumption. The idea is that the revenue generated will be neutral.

Mr. WYNN. Am I hearing you say that even though consumption is down you would maintain this rate level?

Mr. MASON. Yes, because hypothetically what would happen is, let us say that per MCF you had two cents going toward something and the home was using 100 MCF, now that it is using 80 MCF instead of, say, that two cents becomes 2.16, or something like that.

Mr. WYNN. But you would actually increase?

Mr. MASON. OK, but per home the same dollar amount flows through.

Mr. WYNN. All right. And quickly, between Mr. Wright and Mr. Kessler there seems to be a disagreement regarding the 7 year reassessment interval. I guess, I just want to ask, Mr. Wright, are you indicating that you do not believe that the waiver provisions would be adequate to address your concerns?

Mr. WRIGHT. Actually, we agree with the Deputy Secretary's recommendation, which does provide for statutory relief through that process. The difficulty between just relying on the waiver is that it is sort of an ad hoc approach that requires reinventing the wheel almost every time, and depending on what staff member you are in front of, you may get a different interpretation. If they had the backbone of some statutory guidelines it would make the process much more efficient and perhaps even, and I do not want to speak for PHMSA, but would reduce or make more efficient the effort.

Mr. WYNN. Mr. Kessler, the thrust of your testimony was that we maintain the 7 year reassessment interval while you acknowledged that you thought the waiver was appropriate, why do you believe that satisfies Mr. Wright's concerns?

Mr. KESSLER. Well, Mr. Chairman, again the committee and Congress enacted that as a compromise with industry support and because, again, I think being able, if we are going to extend periods for reinspection, going with the risk-based approach, it should be on an individual pipeline basis based upon the risks of that particular pipeline. I would also point out that we had deregulation of sorts since—approaching the early '90s and it was coupled with a de-enforcement and the result was a disaster that we saw in Bellingham and in El Paso with six, eight kids killed in just over a year period. That is why the backstop of the 7 year but again the committee and we all agreed that there should be a way to extend those periods on a case-by-case basis if it was sound to do so.

Mr. WYNN. Thank you. At this time I want to recognize Mr. Walden.

Mr. WALDEN. Thank you, Mr. Chairman.

Mr. WYNN [continuing]. For 5 minutes.

Mr. WALDEN. Appreciate that. I just have one question I want to lay out there and get your input on and that involves the distribution of the user fees and Mr. Preketes, did I get close? Good. Do you think there can be a more equitable distribution of user fees to different pipeline sectors like transmission and distribution and Mr. Wright, maybe you can comment on that same issue as well.

Mr. PREKETES [continuing]. Well, AGA and APGA, respectively, disagreed with the written testimony regarding the user fees. We think the issue is not which segment of the industry pays user fee——

Mr. WALDEN. Right.

Mr. PREKETES. Gas transmission or distribution but which end users of the natural gas pay the user fees. When Congress intended the user fees be put on the transmission pipeline, it was 100 percent of the gas flows through that pipeline so all end users end up paying that.

Mr. WALDEN. Right.

Mr. PREKETES. But if you look at the country using 22 TCF, about half of that goes through the transmission pipes to customers and never goes through distribution. The other half goes to distribution, and if you put all that fee on the distribution we think it is an error because all end users eventually benefit from all those rules. Things like that are in there. Like control excavation damage, prevention, and integrity management, whether it be distribution or transmission we believe benefit all customers therefore keep the fee the way it is. Then all end users will pay the fees it equates.

Mr. WALDEN. Mr. Wright, do you want to comment on that?

Mr. WRIGHT. Our position is now and has been that all stakeholders involved in and benefiting from the oversight and regulations and participating in the process should share in the fees.

Mr. WALDEN. OK. All right. Mr. Chairman that is the only question I had. Given we are out of time, really. I apologize we have got a few others to ask but——

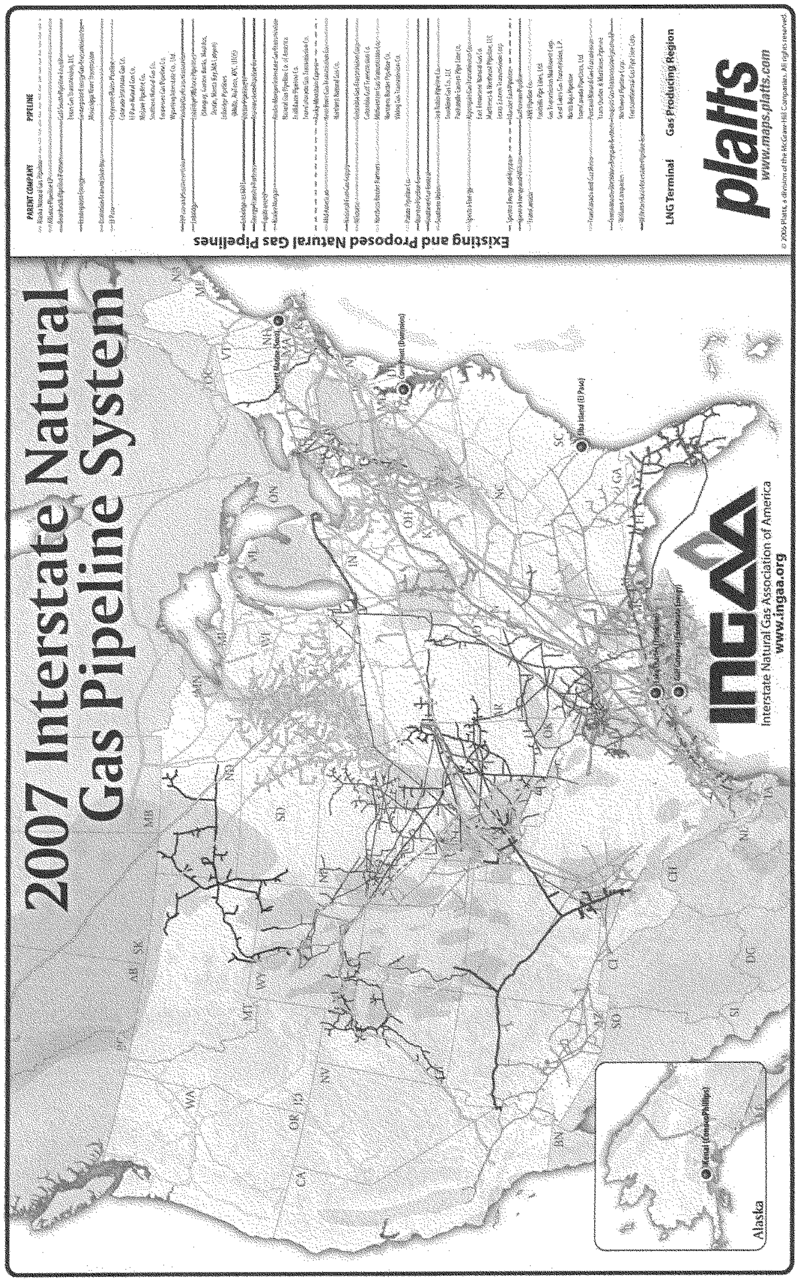
Mr. WYNN. Well, we do have—you do have a few more minutes if you——

Mr. WALDEN. I have got to get over there, so.

Mr. WYNN. All right. Well, if there are no further questions I want to thank the panelists for their participation and their testimony. This will conclude the hearing. I would like to remind members that they may submit additional questions for the record to be answered by the relevant witness. The question should be submitted to the committee clerk within the next 10 days and the clerk will notify your offices of the procedures. Without objection, the committee is now—subcommittee, excuse me—is now adjourned.

[Whereupon, at 1:00 p.m., the subcommittee was adjourned.]

[Material submitted for inclusion in the record follows:]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